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AN ANALYSIS OF THE SIKORSKI BILL, H.R. 4567, TO CONTROL ACID RAIN

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D.W. South, and D.G. Streets

Energy and Environmental Systems Division
Policy and Economic Analysis Group

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SUMMARY

One of the most significant acid rain control bills introduced to the 99th Congress was H.R. 4567, introduced by Rep. Sikorski on April 10, 1986, and reported out of the House Subcommittee on Health and the Environment in amended form on May 20, 1986. The bill never reached a debate in full committee, however.

The Sikorski bill essentially consists of a two-phase program to limit utility sulfur dioxide (SO_2) emissions to a statewide average rate of 2 lb/10^6 Btu by 1993 and 1.2 lb/10^6 Btu by 1997. Emissions of nitrogen oxides (NO_x) and emissions from industrial boilers, industrial processes, and transportation sources would also be reduced.

It is estimated that Phase I would reduce utility SO_2 emissions by 2.6 x 10^6 tons/yr by 1993, relative to the base-case forecast for that year. Phase II would reduce utility SO_2 emissions by 6.1 x 10^6 tons/yr by 1997. The approximate costs are \$0.7 x 10^9/yr for Phase I and \$2.2 x 10^9/yr for Phase II. These cost estimates are compared with similar estimates made by ICF Incorporated for the U.S. Environmental Protection Agency. The ANL estimates are lower than estimates prepared by ICF Incorporated because of different assumptions about the base-case forecast in the absence of an acid rain control bill.

The Sikorski bill is estimated to also achieve a reduction in utility NO_x emissions of about 1.3 x 10^6 tons/yr at a cost of \$400 x 10^6/yr. Reductions in SO_2 emissions from industrial boilers would be about 220,000 tons/yr, but no reduction in industrial boiler NO_x emissions would be required. NO_x emission reductions from mobile sources would amount to 400,000-500,000 tons/yr after the turn of the century.

In general, state-level electricity rates are not expected to increase by more than 6 to 8% when pollution control costs are equally distributed (in terms of percent electricity rate increases) among residential, commercial, and industrial users. In fact, only 13 states are expected to have rate increases greater than 1%. Since the legislation authorizes a subsidy for use in states with residential rate increases over 10%, it is unlikely that utilities will be able to take advantage of any subsidies from the Acid Deposition Fund if all users share the costs of pollution control. If pollution control costs were financed solely by residential users, however, average rate increases for eight states (Illinois, Indiana, Kentucky, Missouri, New Hampshire, Ohio, Pennsylvania, and West Virginia) are expected to increase by over 10%. Rate increases for these eight states range from 11 to 22%.

Electricity rates paid by electricity-intensive industries in the states where rate increases would be highest are similar to or lower than the national industrial average, and are typically less than the state industrial average. For the five most electricity-intensive industries, electricity rates are often substantially less than either the national or state industry average. These industries (electrometallurgical products, primary zinc, primary aluminum, alkalies and chlorine, and industrial gases) might modify their production activities in response to electricity rate changes. They probably would not relocate solely as a result of these changes. Nevertheless, there may be establishments in the high-impact states examined that would be severely affected. For example, the primary zinc and aluminum sectors are being severely hurt by imports and a small difference in purchased energy costs might be critically important to them.

Two aluminum producers, National-Southwire Aluminum (NSA) and ARCO in Kentucky, are examples of marginal companies that may be adversely affected by the legislation. These two companies account for 75% of the power generated by Big Rivers Electric Corporation. Big Rivers has financial difficulties and may default on $1.1 billion in loans. NSA claims that it would have to shut down its Kentucky plant if Big Rivers increased electricity rates. NSA accounts for 900 jobs, amounting to payroll and benefits of approximately $28 million annually. Projected electricity rate increases in Kentucky of 1.5 to 3.5% due to H.R. 4567 would exacerbate the present situation.

The coal-mining industry would also be affected by the legislation since many utilities would switch from a high-sulfur coal to a lower-sulfur coal as a means of controlling SO_2 emissions. If the proposed legislation were to be enacted, coal production and employment are projected to decrease in high-sulfur coal regions such as Northern Appalachia and the Midwest, while the demand for lower-sulfur coal from regions such as Central Appalachia and the Great Plains is expected to increase.

1 INTRODUCTION

The 99th Congress saw renewed interest in proposed legislation to control acid rain. Twenty bills were introduced, 12 in the House and 8 in the Senate. Sixteen of them called for major reductions in sulfur dioxide (SO_2) emissions, generally in the range of 10 to 12 x 10^6 tons/yr, and several bills also called for reductions in nitrogen oxide (NO_x) emissions. Table 1.1 summarizes the acid rain bills from the 99th Congress.

On April 10, 1986, Rep. Gerry Sikorski introduced to the second session of the 99th Congress a bill, H.R. 4567, to amend the Clean Air Act to reduce acid deposition. The bill had 150 cosponsors, including Rep. Henry Waxman, Chairman of the House Energy and Commerce Subcommittee on Health and the Environment, and many other congressmen who had previously introduced bills to control acid rain: Reps. Conte, Udall, Rinaldo, Scheuer, Green, Aspin, Gregg, Solomon, St Germain, and Vento. Such broad, bipartisan support ensured that the bill would become the major focus of acid rain control in the House during the 99th Congress.

As a result of amendments introduced in the subcommittee, a revised version of H.R. 4567 was prepared. The amended version of the bill was reported out of the

TABLE 1.1 Summary of Acid Rain Bills from the 99th Congress

			Coverage of the Bill			
Bill	Major Sponsor	Proposal Date	Acid Rain: Emission Reductions[a]	Acid Rain: Control Fund	Acid Rain: Accelerated Research, Mitigation	Trans-Boundary Air Pollution
S. 52	Stafford	01-03-85	10/1-1-94		X	X
S. 283	Mitchell	01-24-85	10/10AE			
H.R. 1030	Conte	02-07-85	12[b]/10AE	X	X	
H.R. 1162	Green	02-20-85	10[b]/1-1-93			
S. 503	Proxmire	02-25-85	10/1-1-98		X	
H.R. 1414	Green	03-05-85	10[b]/1-1-93			
H.R. 2631	Whitley	05-23-85			X	
H.R. 2679	Udall	06-05-85	10[b]/1-1-96		X	
H.R. 2753	Walgren	06-12-85				X
H.R. 2918	Rinaldo	06-27-85	10[b]/1-1-96	X	X	
H.R. 2963	Weaver	07-10-85			X	
H.R. 3677	Solomon	11-01-85	10/1-1-96		X	
S.1983	Kerry	12-18-85	12[b]/12-31-94	X	X	
S.2003	Moynihan	01-21-86	10/1-1-94		X	X
H.R. 4129	Scheuer	02-05-86			X	
S.2200	Mitchell	03-18-86	10/10AE			X
S.2203	Stafford	03-18-86	NS/NS		X	X
H.R. 4567	Sikorski	04-10-86	NS[b]/1-1-97	X		X
H.R. 4567(Am.)	Sikorski	05-20-86	NS[b]/1-1-97	X		X
S.2813	Proxmire	09-12-86	NS[b]/1-1-97		X	X
H.R. 5675	Kemp	10-08-86	NS[b]/1-1-97			

[a]Amount of SO_2 reduction required (10^6 tons/yr) and date by which compliance is to be achieved. 10AE means ten years after enactment. NS means not specified in the bill.

[b]Plus a reduction in future emissions of nitrogen oxides through revision of new source performance standards and mobile source emission limitations.

Bill H.R. 4567 (Am.) was reported out of the House Energy and Commerce Subcommittee on Health and the Environment. Bill H.R. 2631 was approved by the U.S. House of Representatives 8/13/86.

subcommittee on a 16-9 vote on May 20, 1986. It did not, however, reach a debate in the full committee before the end of the 99th Congress. Table 1.2 summarizes the essential elements of H.R. 4567, and Appendix A reproduces the full text of the amended version of the bill. To avoid confusion, the version of the bill that was originally introduced is not detailed here. All analysis that follows refers to the amended version.

The bill was an attempt by Reps. Sikorski and Waxman to succeed in passing legislation to control acid rain, following the narrow defeat in subcommittee of their bill H.R. 3400 from the 98th Congress. However, H.R. 4567 contained a different approach to reducing precursor emissions than did their previous bill. Instead of mandating emission reductions in terms of tonnage, and forcing specific utility units to scrub, H.R.

TABLE 1.2 Summary of H.R. 4567 as Reported from Subcommittee

	Acid Deposition Control Act of 1986
Impact region:	Entire United States.
Fossil utility reductions:	By 1/1/93, average annual statewide SO_2 emissions must not exceed 2.0 lb/10^6 Btu. By 1/1/97, average annual statewide SO_2 emissions must not exceed 1.2 lb/10^6 Btu, and NO_x emissions must not exceed 0.6 lb/10^6 Btu.
Fossil industrial boiler reductions:	By 1/1/97, average annual statewide SO_2 emissions must not exceed 1.2 lb/10^6 Btu, and NO_x emissions must not exceed 0.6 lb/10^6 Btu.
Industrial process reductions:	By 1/1/97, total annual reduction of SO_2 achieved in each state equal to amount EPA determined on 12/31/90 was economically and technically achievable.
Regulatory agency deadlines:	EPA guidelines: 9 months from enactment, for all State plans.
	Utility: State plans for both 1993 and 1997 due to EPA 21 months after enactment.
	Industrial Boiler: State plans due to EPA 1/1/94.
	Industrial Process: EPA targets due to states 12/31/90. State plans due to EPA by 1/1/94.
	EPA Approval: Approval required 9 months after submittal. Conditional approval is expressly prohibited.
Default provisions:	For utility and industrial boilers, failure to have approved State Plan: specified emission rates and compliance dates apply on <u>unit</u> basis. For industrial process reductions: EPA promulgation of plan by 1/1/95.
Study and mid-course correction:	By 6/30/93, EPA to submit to Congress a study of deposition reduction achieved under Phase I of the utility reduction, and on the feasibility of utility Phase II and the industrial boiler and processes reduction requirements. After review of the study, but before 1/1/94, Congress may enact legislation to halt these requirements.

TABLE 1.2 (Cont'd)

Acid deposition control fund:	EPA shall impose a fee on generation (by fossil fuel) and import of electricity, in order to subsidize some utility residential rate increases caused by the SO_2 requirements of this Act. Fee may be effective 12/31/88 to 12/31/96, and shall not exceed 1/2 mill per kWh. Subsidized payments are to protect residential customers from rates more than 10% higher than in the absence of this legislation.
Innovative technologies:	Discretionary EPA program established to provide financial assistance to sources that will employ innovative emission control technologies. Eligible costs can include design and feasibility studies and annualized costs of technologies not yet in general use, but which EPA in consultation with DOE determines have commercial potential within 10 years of enactment, and have greater economic, environmental and/or social (i.e., prevent fuel switching) benefits than conventional technology. All funding for projects to come from up to 1/4 mill/kWh fee assessment by EPA within State which applied for fee and where project is located. If innovative technology is compliance strategy for any source in reduction plans under this Act, contingent emission limitations must be concurrently submitted by EPA in case technology fails.
Revised NSPS requirements:	EPA to revise utility NO_x NSPS to rates of 0.3 lb/10^6 Btu for subbituminous coal and and 0.4 lb/10^6 Btu for bituminous coal (30-day rolling average); applicable to units commencing construction after date of enactment. EPA to promulgate NO_x NSPS for all fossil steam generating units greater than 50 x 10^6 Btu/hr.
Smelter requirements:	All smelters to be in compliance with SO_2 SIP requirements by 1/1/88; no administrative or judicial extensions permitted.

Mobile source requiremetns:	NO_x Emission Rates:	
	Model Year 1989	
	Passenger Cars	0.7 g/mi
	Model Year 1988	
	Gasoline and diesel trucks (<6000 lb)	1.2 g/mi
	Gasoline and diesel trucks (6000 - 8500 lb)	1.7 g/mi

TABLE 1.2 (Cont'd)

	HC Emission Rates Model Year 1990 Trucks (<6000 lb) 0.41 g/mi Trucks (6000-8500 lb) 0.53 g/mi
Fuel requirement:	After 1/1/89, sulfur in diesel fuel limited to 0.05% by weight.
Evaporative hydrocarbon requirements:	Six months after enactment, EPA to require (1) use of on-board HC control technology on model year 1989 and later vehicles; and/or (2) vapor recovery controls at the gasoline pump.
U.S./Mexican cooperation:	By 3 months after enactment, EPA and State Department are to conclude the transboundary air pollution Annex to the 1983 Border Environmental Agreement with Mexico; emphasizes requiring NSPS at Mexico's new Nacozari smelter and NSPS on expansion of Mexico's Cananea smelter. Also cooperative monitoring, inspection, and enforcement program for these Mexican smelters and the U.S. smelter at Douglas, Arizona.
Studies/reports required:	(1) DOS and EPA to report 6 months after enactment on U.S./Mexican cooperation; 2) EPA to perform atmospheric field experiments on the effects of SO_2 emissions from Nacozari (Mexico) smelter, before and after controls, on states of Arizona, Colorado, Indiana, Montana, New Mexico, Utah, and New York; and (3) DOS, in consultation with EPA and using new (or established) international body, to report on copper smelter transboundary air pollution effects on U.S. and Mexican public health and welfare, with recommendations on preventing any endangerments found.

4567 requires that states meet emission rate limits. The essence of H.R. 4567 is a two-phase program to reduce sulfur dioxide emissions from electric utility power plants. Under Phase I of the bill, statewide emissions of SO_2 from all fossil-fuel-fired electric-utility steam-generating units would be limited to an average yearly emission rate of 2 lb/10^6 Btu by January 1, 1993. Under Phase II of the bill, this emission rate limit would be lowered to 1.2 lb/10^6 Btu by January 1, 1997. Emissions of NO_x from utility boilers would be limited to a statewide average yearly emission rate of 0.6 lb/10^6 Btu by January 1, 1997.

Similar restrictions were placed on emissions from industrial boilers in a single-phase program, with a 1.2 lb/10^6 Btu ceiling on the average SO_2 emission rate and a

$0.6\ lb/10^6$ Btu ceiling on the average NO_x emission rate required by January 1, 1997. Industrial process emissions of SO_2 and NO_x would be reduced by amounts determined by the U.S. Environmental Protection Agency (EPA) to be economically and technically achievable.

Revised state implementation plans (SIPs) for utility boilers would be required one year after enactment, and revised state plans for industrial boilers and sources of process emissions would be required by January 1, 1994. For utility and industrial boilers, failure to have an approved state implementation plan in place would result in application of the specified emission rates and compliance dates to *individual units*, as opposed to statewide averaging.

Emission rates from mobile sources would also be tightened. Allowable emission rates for nitrogen oxides from model year 1989 passenger cars and MY 1988 gasoline- and diesel- powered trucks would be further reduced, as would hydrocarbon emissions from MY 1990 trucks. After January 1, 1989, sulfur in diesel fuel would be limited to 0.05% by weight.

The other major aspect of H.R. 4567 is the establishment of an acid deposition control fund within the Treasury. The EPA would be authorized to impose a fee on electricity generated through fossil-fuel combustion, in order to subsidize electric utilities to ensure that residential electricity rates would not increase by more than 10%. The fee payment schedule would run from December 31, 1988, through December 31, 1996, and the fee would be limited to 0.5 mill/kWh.

This report is the third in a series of analyses of proposed legislation to control acid rain. The two previous reports are *An Analysis of Proposed Legislation to Control Acid Rain*, ANL/EES-TM-209 (Jan. 1983),[1] and *Proposals for Acid-Rain Control from the 98th Congress*, ANL/EES-TM-281 (Oct. 1984).[2] The modeling techniques used are very similar, but direct comparisons of control costs and emission reductions should not be made.

2 METHODOLOGY

This section describes computer models and data bases that were used for the H.R. 4567 analysis. Emission reductions and control costs for complying with acid rain bill provisions were estimated for two air pollutants (SO_2 and NO_x) and for three energy sectors (utility, industrial boiler, and transportation).

2.1 UTILITY SECTOR

The Sikorski bill requires statewide utility SO_2 emissions from fossil-fuel-fired electricity-generating units to be less than 2.0 lb/10^6 Btu in 1993. Emission limits are further tightened in 1997 when the SO_2 emission rate is lowered to 1.2 lb/10^6 Btu, and the NO_x emission rate is limited to 0.6 lb/10^6 Btu. Estimating emission reductions and control costs associated with achieving H.R. 4567 provisions is a twofold problem. First, projections of utility emission rates for 1993 and 1997 must be made. Second, emission reductions and control costs to achieve the mandated levels must be determined.

2.1.1 Utility Emission Rate Projections

Future utility emission levels for coal, oil, and gas units were estimated with a modified version of the AIRCOST model.[2-4] Initially, the model computes state-level emission and fuel consumption levels for 1980. These estimates are based on a 1980 data base of electricity-generating units and serve as a benchmark from which projections of future emission and fuel consumption levels are made.

The 1980 unit-level data set is a subset of the NAPAP Utility Reference File (NURF) that was developed by E.H. Pechan & Associates for EPA.[5] The 1980 data set contains approximately 50 data elements consisting of unit operating characteristics and regulatory information. Unit-level data elements include on-line date; location; capacity; heat rate; capacity factor; fuel quality and quantity; pollution control equipment; and regulatory emission limits for SO_2, NO_x, and particulates.

Trends in utility emissions from 1980 to 1985 and projected trends beyond 1995 are based on documented changes in the utility sector since 1980 and projections of the future behavior of the utility sector. Additional units representing growth in the electric utility sector are added to the 1980 data set. These units consist of units that (1) have been constructed between 1980 and the present, (2) are currently under construction, (3) are in the planning stage, and (4) are constructed by AIRCOST to meet future electricity demands.

Units on line since 1980, under construction, or in the planning stage are contained in a utility update file developed by E.H. Pechan & Associates. The update file is also a subset of NURF and contains anticipated on-line dates for units that are under construction or in the planning stage. These units may be placed on either a delayed or accelerated construction schedule by the model, thereby altering the anticipated on-line date. The impetus for changing the on-line date is the projected demand for electricity. When the schedule of on-line dates for new units differs from electricity demand projections, on-line dates are adjusted such that the construction of new units is in agreement with the level of projected demand.

Additional generic electricity-generating units are "constructed" if generating units on line ina projection year cannot satisfy the projected electricity demand. The characteristics of generic units differ by state and are based on projected state-level electricity demand increases, the historical characteristics of existing units in that state, and the projected cost and quality of available fuels.

A second utility update file used by AIRCOST contains a list of flue-gas desulfurization (FGD) units that have come on line since 1980, are currently under construction, or are scheduled to be built in the future. These data were obtained from the PEDCo Environmental, Inc., FGD Survey.[6] FGD devices are retrofited on existing units and installed on newly built units according to the FGD data base.

Projections of utility coal, oil, and gas consumption are based on reference scenario energy projections from the Fifth National Energy Policy Plan (NEPP-V)[7,8], as discussed in Sec. 3. NEPP-V contains national-level energy projections in five-year increments to the year 2010. A linear interpolation method was used to estimate consumption levels for 1993 and 1997. State-level coal, oil, and gas consumption for these years is determined by applying a state-level fractional share to national-level energy projections. State shares were estimated by the Argonne Regionalization Activity Module (ARAM). ARAM is a disaggregation model that allocates national-level fuel consumption to state-level fuel consumption through the use of a shift-share algorithm. Beginning with base yeart 1980 values by region, and taking into account national growth, the state shifts in shares are based on a forecast of related economic activity variables, such as employment in the associated industry.

The regionalization algorithm employed in ARAM is identified below:

$$\mathrm{ELEC}_{j,s}(k) = [\mathrm{ELEC}_{n,s}(k)] \frac{[\mathrm{ELEC}_{j,s}(1980)][\mathrm{ACTINDEX}_{j,s}(k)]}{\Sigma\,[\mathrm{ELEC}_{j,s}(1980)][\mathrm{ACTINDEX}_{j,s}(k)]}$$

where:

$\mathrm{ELEC}_{j,s}(k)$ = state level j electricity demand by end-use sector s and time k.

$\mathrm{ELEC}_{n,s}(k)$ = national electricity demand by end-use sector s and time k.

$\mathrm{ELEC}_{j,s}(1980)$ = base year (1980) electricity demand by state j and end-use sector s.

$\mathrm{ACTINDEX}_{j,s}(k)$ = activity index (1980 = 1.0) by state j, end-use sector s and time k. Employment is the activity variable indexed for the commercial and industrial sectors (commercial sector employment, manufacturing and nonmanufacturing employment, respectively). Population is the activity variable for the residential sector.

s = end-use sectors: residential, commercial and industrial, with industrial disaggregated into manufacturing and nonmanufacturing.

r = 50 states and the District of Columbia.

k = simulation year.

According to the regionalization algorithm, regional-level electricity demand by sector is projected over time by multiplying a sector-specific forecast of national electricity demand by an energy-weighted shift-share factor. The shift-share factor varies by end-use sector and time in each state. A more detailed explanation of ARAM is documented elsewhere.[9,10]

Projections of future emission levels are sensitive to assumptions pertaining to the retirement age of units, capacity factors of existing units, utility SIP compliance schedules, and future New Source Performance Standards (NSPS) limits.

For this study, it was assumed that all units (coal, oil, and gas) retire 50 years from their on-line date. Coal units on line in 1980 continue to operate at their 1980 utilization rates until they reach their retirement age. Coal units coming on line after 1980 operate at a 57% capacity factor and continue to do so until they retire. Capacity utilization rates for oil- and gas-fired utilities are adjusted such that state-level oil and gas consumption is consistent with oil and gas consumption projected by NEPP-V.

State implementation plan units that were not in compliance in 1980 are assumed to comply with SIP limits by 1990. The remaining units are regulated by either 1971 NSPS or 1979 NSPS, depending upon when the units came on line. Emission limits for these more stringently regulated units are provided in Tables 2.1 and 2.2, respectively. It was assumed that the NSPS requirements provided in Tables 2.1 and 2.2 will not be tightened before 1997. Although the 1979 NSPS limit for oil and gas units is 0.8 lb/10^6 Btu with a 90% FGD removal rate, it was assumed that these units meet a 0.2 lb/10^6 Btu emission rate so that the removal requirement is waived. Likewise, NO_x emission rate requirements for coal, oil, and gas units regulated under 1979 NSPS are met without emission control devices, thereby overriding the percent removal requirement.

In addition to being sensitive to assumptions concerning the configuration and operating characteristics of units, emission projections are also sensitive to the quality of fuel burned. In general, units on line before 1981 will, in the future, continue to burn the same fuel that they did in 1980. These pre-1981 units will only switch fuels if they were not in compliance with SO_2 emission limits in 1980. Units on line after 1980 are assigned a fuel by AIRCOST. The model assigns a fuel by selecting the cheapest fuel and emission control technology combination that will meet the required emission limit.

TABLE 2.1 1971 New Source Performance Standards for New Fossil-Fuel-Fired Steam Generators Larger Than 250 x 10^6 Btu/hr Heat Input

Pollutant	Emission Limit[a] ($lb/10^6$ But), by Fuel Type		
	Coal	Oil	Gas
Sulfur dioxide	1.2	0.8	-
Particulate matter	0.1	0.1	0.1
Nitrogen oxides	0.7	0.3	0.2

[a]Implementation based on a 30-day rolling average.

Coal-fired units select from a set of coal alternatives generated by the AUSM coal supply module. The AUSM module was modified in such a way that coals having small estimated reserves, or reserves that have not been mined in the past, were not considered as viable coal-switching options. Oil- and gas-fired units burn a generic fuel that meets SO_2 emission requirements. The prices of oil and gas are based on 1985 Form 423 cost and quality of fuel data.[11] Algorithms that estimate costs for pollution control devices were extracted from the AUSM pollution control module.[12]

As part of the fuel selection process for NSPS units, AIRCOST accounts for the variability of sulfur within the fuel to ensure that SO_2 emission limits are not violated during any averaging period. This variability is assumed to be negligible for oil and gas, but is substantial for coal. The model accounts for coal sulfur variability by applying a relative standard deviation factor to the average sulfur content. For a 30-day averaging time period, the model multiplies the annual average sulfur content by 1.2 in order to estimate the peak 30-day rolling average sulfur content. For example, to meet a 1.2 $lb/10^6$ Btu limit based on a 30-day rolling averaging time, a coal that has a maximum annual average SO_2 emission rate of 1.0 $lb/10^6$ Btu must be burned.

SO_2 Emissions

SO_2 emission projections for coal and oil units are based on unit size, boiler capacity factor, boiler heat rate, and fuel quality. The following mass balance equation is used to compute annual SO_2 emissions for coal- and oil-fired units:

$$SO_2E = MW \times CF \times HEATR8/HHV \times S \times (1.0 - CEM) \times (1.0 - REMSO_2) \times 0.0876$$

TABLE 2.2 1979 Revised New Source Performance Standards for New Fossil-Fuel-Fired Steam Generators Larger Than 250 x 10^6 Btu/hr Heat Input

Pollutant	Fuel Type Coal	 Oil	 Gas
Sulfur dioxide	1.2[a] 90%[b]	0.8[a] 90%[c]	0.8[a] 90%[c]
Particulate matter	0.03[a] 99%[d]	0.03[a] 70%[d]	0.03[a] -
Nitrogen oxides	0.6[a,e] 65%[d,h]	0.3[a,f] 30%[d,h]	0.2[a,g] 25%[d,h]

[a]Emission limit in lb/10^6 Btu heat input (based on a 30-day rolling average).

[b]Percent reduction required, unless emissions are less than 0.6 lb/10^6 Btu, in which case 70% reduction is required.

[c]No percent reduction required if emissions are less than 0.2 lb/10^6 Btu.

[d]Percent reduction required.

[e]Solid fuels, except subbituminous coal (0.5), coal-derived fuels (0.5), and certain lignite-containing fuels (0.8).

[f]Except shale oil (0.5) and coal-derived liquids (0.5).

[g]Except coal-derived gases (0.5).

[h]No percent reduction required if emission rate limit is met.

where:

SO_2E = SO_2 emissions (10^3 tons/yr)

MW = unit capacity (MW)

CF = capacity factor

HEATR8 = heat rate (Btu/kWh)

HHV = higher heating value (Btu/lb)

S = average sulfur content (%)

CEM = sulfur retained in bottom ash (fraction)

$REMSO_2$ = FGD SO_2 removal rate (fraction).

The fraction of sulfur retained in the boiler's bottom ash is dependent on the type of fuel burned and is assumed to be 0% for oil, 5% for bituminous coal, 10% for subbituminous coal, and 15% for lignite.

SO_2 removal efficiencies were obtained from the PEDCo FGD survey.[6] Additional FGD units were installed and operated at a removal efficiency such that units meet SO_2 regulatory requirements. SO_2 emission projections for gas-fired units are based on an AP-42 emission factor.[13] It is assumed that gas-fired boilers emit 0.6×10^{-3} tons of SO_2 per 10^6 ft^3 of natural gas burned.

NO_x Emissions

NO_x emissions for utility boilers are based on the type of fuel burned, the boiler's firing type, and the boiler bottom type. Table 2.3 shows AP-42 emission factors that were used in this study to estimate NO_x emissions for coal, oil, and gas units. In 1990, units with NO_x emission rates greater than compliance levels are controlled such that they meet their NO_x regulatory emission limits. Emission factors are multiplied by the amount of fuel consumed to obtain estimates of total tons per year of NO_x emitted.

Particulate Emissions

Although H.R. 4567 does not require more stringent regulations for particulate emissions, it is important that current standards for this pollutant are not violated. For example, a unit that switches to a lower-sulfur coal in order to reduce its SO_2 emission rate may have to upgrade its particulate control devices. The lower-sulfur coal may have a high ash content and a high resistivity. The cost of removing ash from a coal with these characteristics may more than offset the advantages associated with its low sulfur content. Particulate emissions from coal-fired units are based on boiler operating characteristics, the quality of fuel burned, and the particulate control devices. The

TABLE 2.3 Uncontrolled NO_x Emission Factors for Fossil-Fuel-Fired Utility Boilers

Boiler Fuel	Firing Type	Emission Factor (lb NO_x/ton)		
		Wet Boiler Bottom	Dry Boiler Bottom	No Data[a]
Bituminous and Subbituminous Coal and Anthracite	Single wall	34.0	21.0	22.8
	Opposed wall	34.0	21.0	21.9
	Tangential	34.0	15.0	16.6
	Spreader stoker	14.0	14.0	14.0
	Cyclone	37.0	37.0	37.0
	No data[a]	35.6	18.1	21.1
Lignite	Single wall	14.0	14.0	14.0
	Opposed wall	14.0	14.0	14.0
	Tangential	8.0	8.0	8.0
	Spreader stoker	12.0	12.0	12.0
	Cyclone	12.0	12.0	12.0
	No data[a]	12.0	9.0	9.5
		Emission Factor (lb $NO_x/10^3$ gal)		
Oil	Tangential	42.0		
	Others	67.0		
	No data	57.7		
		Emission Factor (lb $NO_x/10^6$ ft^3)		
Natural Gas	Tangential	275.0		
	Others	550.0		
	No data	478.8		
Turbine Fuel		Emission Factor		
Oil		67.8 lb $NO_x/10^3$ gal		
Natural Gas		113.0 lb $NO_x/10^6$ ft^3		

[a]Emission factors represent average weighted (by capacity) factors over all 1980 utility boilers that had boiler bottom or firing type data.

following equation is used to compute annual particulate emissions from coal-fired boilers:

$$PARTE = ASH/HHV \times CF \times MW \times HEATR8 \times 0.1752 \times (1.0 - REMPAR)$$

where:

PARTE = particulate emissions (10^3 tons/yr)

ASH = coal ash content (%)

HHV = higher heating value (lb/10^6 Btu)

CF = capacity factor

MW = unit size (MW)

HEATR8 = unit heat rate (Btu/kWh)

REMPAR = particulate control removal efficiency (fraction).

Particulate emissions from oil-fired steam units are based on AP-42 emission factors. For units burning residual oil, the following relationship was used:

$$PARTR = (10.0 \times S) \times 3.0 \text{ lb}/10^6 \text{ gal} \times (1.0 - REMPAR)$$

where:

PARTR = particulate emission rate (lb/10^6 gal)

S = oil sulfur content (% by weight).

Emissions from electricity-generating turbines burning distillate oil are based on an emission factor of 5.0 lb of particulates per 10^6 gallons of oil burned.

Particulate emissions from gas-fired units are also based on AP-42 emission factor. For steam units, particulate emissions are estimated at 2.5 lb/10^6 ft^3 of natural gas burned. Emissions from gas turbines are estimated at 14.0 lb of particulate per 10^6 ft^3 of natural gas burned.

Particulate removal efficiencies were obtained from the 1980 unit-level data set developed by E.H. Pechan & Associates.[5] Additional particulate control devices were installed by the model to ensure that units meet particulate emission requirements.

2.1.2 Utility Emission Reductions and Control Costs

Projections of emissions and fossil-fuel consumption are used to compute average emission rates over all fossil-fuel-fired units located in a state. Projected emission rates are then compared to H.R. 4567 state-level emission rate ceilings, and a required emission reduction is calculated.

The AIRCOST model determines the least-costly method of achieving these reductions by comparing the total levelized costs of a range of available control methods. Available SO_2, NO_x, and particulate control methods included in the model are provided in Table 2.4. Control technology limitations and costs for these technologies were obtained from AUSM. AIRCOST assumes that SO_2, NO_x, and particulate control technologies are independent. That is, one control technology does not have an effect on the cost or performance of the other technology. Certain combinations of control technologies, however, are not allowed by the model. For example, a hot-side ESP cannot be installed on a unit that has a dry FGD system.

Although H.R. 4567 does not require more stringent controls for particulate emissions, SO_2 emission reduction strategies that involve fuel switching may affect the cost and performance of particulate control systems. When this occurs, the capital expenditures for upgrading the particulate control system and changes in particulate O&M control costs are added on to the fuel switching premium.

At each unit, the model examines various combinations of control options for numerous levels of emission control. Unit-level curves are then constructed by connecting emission reduction/control cost points such that they define a convex hull cost frontier. These points are connected in a piecewise linear fashion, the slopes of which represent the marginal cost of going from a less-stringent control strategy to a more-stringent control strategy. Points that lie above the cost frontier are suboptimal control strategies, since these approaches have higher marginal control costs.

TABLE 2.4 Pollution Control Methods Included in the AIRCOST Model

Pollutant	Emission Control
SO_2	Coal cleaning Coal switching and blending Oil desulfurization Wet FGD systems Dry FGD systems
NO_x	Low excess air (LEA) Low NO_x burners (LNB) Selective catalytic reduction (SCR)
Particulates	Cold-side electrostatic precipitators (ESP) Hot-side electrostatic precipitators Fabric filters

All unit-level curves in a state are aggregated to produce a state-level curve of cost versus emission reduction. This is achieved by rank ordering marginal cost curve segments from lowest to highest. Because alternatives that achieve the lowest cost per quantity of emissions reduced are selected first, as more emission reduction is demanded, the cost of achieving the last ton of reduction increases. With this type of piecewise linear analysis, the least-cost solution often lies between two discrete pollution control end points. The model must, therefore, "over control" such that the emission reduction requirement is satisfied. Since the model is run for numerous emission control reduction levels and for each unit, the amount of overcompliance is usually very small.

2.2 INDUSTRIAL SECTOR

The H.R. 4567 emission constraints for industrial boilers are identical to utility boiler constraints with the exception that the 1993 2.0 lb/10^6 Btu statewide emission limit for SO_2 is not required. The emission reductions in 1997 that would result from a required statewide emission rate ceiling of 1.2 lb/10^6 Btu for SO_2 and a 0.6 lb/10^6 Btu ceiling for NO_x were based on NEPP-V reference scenario energy and emission projections for industrial boilers. Emission projections at the state level for coal, oil, and gas boilers were obtained from information that was generated for the NEPP-V Environmental Assessment.[14]

Average statewide emission rates were compared to H.R. 4567 emission rate ceilings and required emission reductions were computed. Due to the generic nature of this methodology, control costs associated with industrial boiler emission reductions were not made.

2.3 TRANSPORTATION SECTOR

H.R. 4567 mandates a revised "final" standard of 0.7 g/mi for exhaust emissions of NO_x from light-duty vehicles built for the 1989 model year and thereafter. This level is 30% more stringent than the current final standard of 1.0 g/mi enacted in 1981, pursuant to the requirements of the Clean Air Act Amendments of 1977. Emission reductions and control costs associated with achieving this more-stringent standard were estimated by the Transportation Emission Reduction Model (TERM).[15] Model estimates are made for four different light-duty vehicle classes consisting of:

1. Light-duty gasoline vehicles (LDGV),

2. Light-duty diesel vehicles (LDDV),

3. Light-duty gasoline trucks (LDGT), and

4. Light-duty diesel trucks (LDDT).

2.3.1 Transportation NO_x Emission Reductions

Estimates of NO_x emission reductions associated with the more-stringent standard for light-duty vehicles are made for the year 1989 and for each year thereafter until the year 2030. Emission reduction projections are computed in terms of tons of NO_x per year and are based on a vehicle registration fraction (i.e., fraction of vehicles of a specified age that are in operation relative to total fleet vehicles in operation as of January 1 of the simulation year). Vehicle registration fractions for each vehicle class were obtained from AP-42 emission factor documentation.

NO_x emission reductions for vehicle class *i*, in state *j*, and for simulation year *k* are estimated by the following relationship:

$$ER_{ijk} = 1.1023 \cdot 10^{-3} \cdot VMT_{ijk} \cdot \sum_{l=1}^{m} VMTF_{il} \cdot \left| (Z2_i + [AM_{il} \cdot DR2_i]) - (Z1_i + [AM_{il} \cdot DR1_i]) \right|$$

where:

ER_{ijk} = NO_x emission reduction (tons/yr).

VMT_{ijk} = total vehicle miles traveled for the fleet of vehicles (10^3 mi/yr).

l = age of vehicle in operation (yr).

m = number of years from regulation implementation date to simulation year (yr).

TF_{il} = fraction of miles traveled for a vehicle of age l relative to total miles traveled for the entire fleet of class i vehicles.

$Z2_i$ = zero-mile NO_x emission rate for a control device meeting the tighter emission regulation (g/mi).

AM_{il} = average accumulated miles for a vehicle that is 1 yr old (10^4 mi).

$DR2_i$ = deterioration rate for a control device meeting the tighter emission regulation (g/mi per 10^4 mi).

$Z1_i$ = zero-mile NO_x emission rate for a control device meeting current emission regulations (g/mi).

$DR1_i$ = deterioration rate for a control device meeting current emission regulations (g/mi per 10^4 mi).

Vehicle miles of travel (VMT) data contained in this model are based on reference scenario energy projections contained in the NEPP-V. National-level NEPP-V data were disaggregated into state and vehicle class VMT by the Transportation Energy and Emissions Modeling System (TEEMS).*[16] The relative fraction of VMT for a specified age is based on (1) the assumed fleet registration fraction, (2) the fraction of vehicles by fuel type (gasoline or diesel) relative to the entire fleet, and (3) the annual mileage accrual rate by year. This fraction, TF_{il}, for vehicle class i, which is l years of age, is estimated by the following relationship:

$$TF_{il} = (RF_{il} \cdot FF_{in} \cdot M_{il}) \; / \sum_{l=1}^{20} RF_{il} \cdot FF_{in} \cdot M_{il}$$

where:

RF_{il} = fleet registration fraction.

FF_{in} = fraction of gasoline- or diesel-fueled vehicles relative to total vehicle sales for simulation year k.

M_{il} = annual mileage accrual rate for vehicle of age l.

n = model year = simulation year - l + 1.

Annual mileage accrual rates were obtained from data contained in AP-42 documentation. Fuel fractions were derived from data contained in AP-42 documentation and from TEEMS model results.

2.3.2 Transportation NO_x Control Costs

The 0.7-g/mi NO_x standard for light-duty vehicles represents the midpoint between the current 49-state standard of 1.0 g/mi and the 0.4-g/mi "research" goal that was added to Sec. 202 of the Clean Air Act and is also the present California standard. Control costs to achieve certification at the 0.7-g level will be greater than costs of the present control systems, but somewhat less than the control systems that meet the 0.4-g/mi research goal.

In general, these costs are for increasing the capacity of the air pump that reduces the combustion temperature in the engine's cylinders and for decreased fuel economy. The California Air Resources Board has estimated that the cost-effectiveness of the 0.4-g/mi standard is about $2,200 per ton of NO_x removed.[17] When compared with EPA's estimate of $500/ton to achieve the 1.0-g/mi standard, a standard of 0.7-g/mi

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*TEEMS has been run with each of the energy scenarios reported in NEPP-V as part of Phase I of the Task Group I program for the National Acid Precipitation Assessment Program.

should therefore cost about $1,000/ton. The incremental cost of removing 30% more NO_x above the current standard is roughly half as cost-effective as achieving the 1.0-g/mi emission rate.

2.4 ELECTRICITY RATE INCREASES

The methodology used to calculate electricity rate increases was as follows. Electricity rate increases were based on projections of future utility revenue requirements, electricity consumption levels, estimates of pollution control costs, and the historical behavior of state-level public utility commissions. Estimates of future electricity consumption levels were based on the NEPP-V reference case and disaggregated to the state and sector (residential, commercial, and industrial) level by the ARAM model.

Future utility revenue requirements were obtained by multiplying forecasts of state/sector-level electricity rates from the Argonne Regional Energy Price Simulator (AREPS) model by future electricity consumption levels. AREPS is a disaggregation model that estimates regional electricity prices on the basis of projections of national-level electricity prices and historical price differences among regions. Details of the AREPS model are provided in Appendix B. Both the ARAM and AREPS models were developed for the National Acid Precipitation Assessment Program (NAPAP) and have been used extensively for the NEPP-V Environmental Assessment.

Pollution control cost estimates were obtained from the AIRCOST model runs described earlier. Additional revenues for financing pollution control expenses were determined on a state-by-state basis. In light of the fact that H.R. 4567 requires that state implementation plans do not result in a disproportionate economic effect on electric utility rate payers in any region of a state, or in any utility service area, average state-level, as opposed to company-level, electricity rate increases were computed.

Utility revenue requirements were computed on a temporal basis and determined by applying standard revenue requirement formulas, while accounting for state-specific procedural characteristics pertaining to tax rates; historical financial splits between debt, common stock, and preferred stock; and public utility commissions' preference for normalization or flow-through accounting procedures. A more-detailed discussion of calculation of utility revenue requirements is provided in Appendix C.

3 EMISSION REDUCTIONS AND CONTROL COSTS

3.1 NATIONAL UTILITY SO_2 FORECASTS

The effect that the Sikorski bill would have on utility SO_2 emissions depends to a large extent on the rate of retirement of existing SIP units and the amount of new fossil-fired capacity brought on line in the future. The greater the number of SIP units operating in the future, and the greater the capacity utilization of such units, the greater will be the effect of the bill. New units controlled under stringent NSPS requirements would be unaffected by the bill. However, the greater the generation of electricity by these new units, the lower the average statewide emission rate. The greater the number of new units operating in the future, and the greater the capacity utilization of these units, the lesser the effect of the bill. Different opinions as to the usage of SIP units in the future have been the cause of differences in estimates of the effects of the Sikorski bill in a number of studies. Assumptions about the future of the electricity-generating industry are therefore of critical importance and a good starting point for a discussion of the broad features of the bill's likely impacts.

In this study, the energy and economic projections of the Fifth National Energy Policy Plan (NEPP-V)[7,8] were used to generate a base-case forecast of utility SO_2 emissions out to the year 2000 in the absence of any acid rain control program. This base case is identical to that presented in ANL's Environmental Assessment of NEPP-V.[14] The base case utilizes energy and economic forecasts for the NEPP-V reference (or "mid-range") scenario, which assumes the following electricity annual growth rates: 1.7% (1980-1984), 2.6% (1984-1990), and 2.4% (1990-2000). By the year 2000, it is projected that there would be 571 GW of fossil-fuel-fired electricity-generating capacity and 110 GW of nuclear capacity. Total fossil-fuel consumption by the electricity sector would amount to about 27 quads in the year 2000.

Other key assumptions for the ANL analysis are that existing coal-fired power plants continue to operate at their current capacity factors for the remainder of their lifetime and that they retire at 50 years of age. This is considered a mid-range estimate of typical retirement ages, but some analysts believe that life extension practices by utility companies could extend plant lifetimes to 60 or 70 years or even longer.[18,19] Computer simulations of electric utility dispatching using ANL's ICARUS model (named for the Investigation of Costs and Reliabilty in Utility Systems) have shown that on average, capacity factors of old units remain constant or decrease slightly over time.

On the basis of these energy assumptions, a profile of future utility SO_2 emissions in the absence of the bill can be constructed. Figure 3.1 shows ANL forecasts of future utility emissions, together with emissions trends since 1980.[20]

The early 1980s saw a significant decline in utility SO_2 emissions from 17.6×10^6 tons/yr in 1980 to 16.1 10^6 tons/yr in 1982. Emissions have remained roughly constant since then. Overall, utility SO_2 emissions have shown a declining trend over the past decade, from a high value of about 19×10^6 tons/yr in 1973.[21]

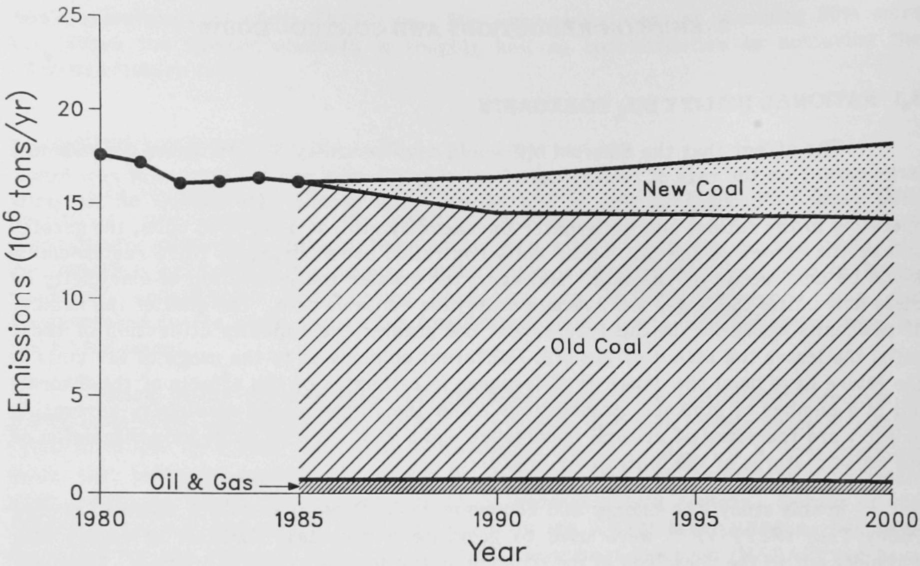

FIGURE 3.1 ANL Projections of Future Utility SO_2 Emission Trends

The ANL projections suggest a reversal of this trend in the near future, with a slow increase in utility SO_2 emissions through the remainder of this century, from 16.2 x 10^6 tons/yr in 1985 to 16.5 x 10^6 tons/yr in 1990, 17.3 x 10^6 tons/yr in 1995, and 18.0 x 10^6 tons/yr in 2000. Growth in electricity demand is the major driving force for this increase.

Figure 3.1 breaks out utility SO_2 emissions into contributions from oil and gas units, "old" coal units (i.e., plants in existence in 1985 -- mainly SIP units), and "new" coal units (i.e., NSPS units coming on line after 1985). Emissions from oil and gas combustion in utility plants remain approximately constant throughout the projection period at about 700,000 tons/yr. Emissions from "old" coal units are projected to decline from about 15.5 x 10^6 tons/yr in 1985 to 13.5 x 10^6 tons/yr as a result of plant retirements. Emissions from "new" units grow from zero in 1985 to 3.9 x 10^6 tons/yr in the year 2000. These units replace generating capacity lost by retiring existing units and are built to satisfy greater electricity demands in the future. It is the "old" coal units that are affected by the emission rate limit of the Sikorski bill.

The AIRCOST model was used to determine the emission reductions that would be achieved by imposition of the Phase I average emission rate limit of 2.0 lb/10^6 Btu by 1993 and the Phase II limit of 1.2 lb/10^6 Btu by 1997, using the methodology described in Chapter 2.

It is estimated that the effect of Phase I would be to reduce utility SO_2 emissions in 1993 by 2.6 x 10^6 tons/yr relative to the base-case forecast and that Phase II would reduce emissions in 1997 by 6.1 x 10^6 tons/yr. The default provisions would achieve greater emission reductions (4.3 x 10^6 tons/yr under Phase I and 7.2 x 10^6 tons/yr under Phase II) because the flexibility offered by statewide averaging is removed under the default provisions.

The AIRCOST model was also used to determine the incremental emission control costs that would be incurred in achieving these emission reductions. The Phase I reductions would cost approximately \$0.7 x 10^9/yr in 1993, and the Phase II reductions would cost \$2.2 x 10^9/yr in 1997. Costs to comply with the default provisions would naturally be higher. Table 3.1 summarizes ANL's estimates of national-level costs and emission reductions projected to occur if H.R. 4567 were to be implemented. Cost-effectiveness values for the four cases are included.

These estimates differ somewhat from those prepared by ICF Incorporated for the U.S. Environmental Protection Agency.[22] It is instructive to examine in some detail the factors that lead to differences between the two studies. Table 3.2 presents a side-by-side comparison of significant results from the two studies. It is immediately apparent from Table 3.2 that ICF projects greater impacts from H.R. 4567 than ANL does. For example, the Phase II reduction would be 8.1 x 10^6 tons/yr according to ICF, as compared to 6.1 x 10^6 tons/yr in this study. The difference arises not in the interpretation of the legislation but rather in the construction of the baseline.

Table 3.2 shows that estimates of total fossil-fuel consumption by electric utilities under Phase I of the bill are very similar in the two studies (23 quads). By the end of Phase II, however, ICF shows two quads more fuel consumption than ANL (26.8 quads vs. 24.8 quads). The additional fossil fuel consumption is all coal. Thus one might

TABLE 3.1 ANL Estimates of the Effects of H.R. 4567 on Utility SO_2 Emissions and Costs

	Emission Reduction (10^6 tons/yr)	Control Costs (1985 \$ x 10^9/yr)	Cost-Effectiveness (\$/ton)
Phase I 1993	2.6	0.7	270
Phase II 1997	6.1	2.2	360
Default 1993	4.3	1.5	350
Default 1997	7.2	3.2	450

TABLE 3.2 Comparison of ANL and ICF Estimates of the Effects of H.R. 4567 on Utilities

		Phase I		Phase II	
	Historical 1980	ICF 1995	ANL 1993	ICF 2000	ANL 1997
Coal Consumption (quads)	12.1	18.04	18.79	22.70	20.67
Oil Consumption (quads)	2.6	1.65	1.34	1.37	1.29
Gas Consumption (quads)	3.8	3.25	2.92	2.76	2.87
Total Consumption (quads)	18.5	22.94	23.05	26.83	24.83
SO_2 Emissions (10^6 tons/yr)					
"Old" Coal	16.08	17.18	13.91	17.51	13.71
Oil/Gas	1.40	1.19	0.74	0.87	0.71
"New" Coal	0.0	1.28	2.45	2.16	3.22
Total	17.48	19.65	17.10	20.53	17.64
Required SO_2 Reductions (10^6 tons/yr)					
Least-cost	-	4.1	2.6	8.1	6.1
Default	-	7.3	4.3	10.4	7.2
Control Costs (1985 \$ 10^9/yr)					
Least-cost	-	0.7	0.7	2.5	2.2
Default	-	3.7	1.5	5.5	3.2
Cost-Effectiveness (1985 \$/ton)					
Least-cost	-	170	270	309	361
Default	-	507	348	529	449
Additional Retrofit FGD Capacity (GW)					
Least-cost	-	0.2	8.0	4.1	19.6
Default	-	29.7	15.4	40.5	28.1

expect higher base-case emissions in the ICF study by the year 2000, although not significantly higher if all the additional coal were burned in NSPS plants.

Note also that this study estimates emissions and costs for the actual compliance years specified in the bill for Phases I and II (1993 and 1997), whereas ICF approximates them to 1995 and 2000. The differences in dates cause a major portion of the discrepancies in the total fuel use (1.6 out of 2.0 quads for Phase II).

Figure 3.2 presents the ICF base-case estimate of utility SO_2 emissions out to the year 2000, in the absence of any acid rain legislation. This figure was constructed from data in Ref. 22. Analogous to Fig. 3.1, emissions are broken out into contributions from oil and gas plants, "old" coal plants, and "new" coal plants.

ICF projects a significantly greater increase in utility SO_2 emissions through the remainder of the century than does ANL. ICF projects that emissions will increase from 16.2×10^6 tons/yr in 1985 to 18.6×10^6 tons/yr in 1990, 19.7×10^6 tons/yr in 1995, and 20.5×10^6 tons/yr in the year 2000. By the year 2000, ICF emission estimates are 2.5×10^6 tons/yr higher than the ANL estimates.

Figures 3.1 and 3.2 clearly show that the major difference between the two studies lies in the emissions from coal-fired units, and, more specifically, in the split between "new" and "old" units. ICF projects only 2.2×10^6 tons/yr of emissions from "new" units in the year 2000, as compared with 3.9×10^6 tons/yr in this study. Since total coal consumption is not greatly different, this implies the ICF assumes (1) a much lower rate of retirement of SIP units and replacement by NSPS units and (2) a higher utilization rate for SIP units. While ICF does not explicitly state the assumed retirement age of coal plants in its study, other recent analyses by ICF[23,24] have used a 60-yr retirement age, which would be consistent with the above discussion.

Of equal significance is that ICF projects an increase in emissions from "old" units over time (from 16.1×10^6 tons in 1980 to 17.5×10^6 tons in 2000), despite the fact that some old units would retire during this period. The most likely explanation for this emission increase is that old plants increase their capacity utilization with time. It is unlikely that these units would switch to higher sulfur coals.

Thus, in the ICF study, SIP plants are operated more, they are retired later, and fewer new plants are constructed. For these reasons, emissions rise more rapidly than in the ANL base case.

Increased utilization of SIP units may be a possible response to increased electricity demand for a few utility systems that are currently overbuilt, but widespread increases are infeasible when questions of reliability and availability are considered.[25] The physical deterioration of old units as they age results in decreased availability and limits any attempt to significantly increase capacity utilization to meet increased demand. ANL assumptions of constant capacity factors for SIP units over time are more reasonable. This premise is supported by ICARUS power pool dispatching simulations for the 1995 through 2010 timeframe. Thus, ANL forecasts a decrease in emissions from "old" units over time: from 16.1×10^6 tons in 1980 to 13.5×10^6 tons in 2000.

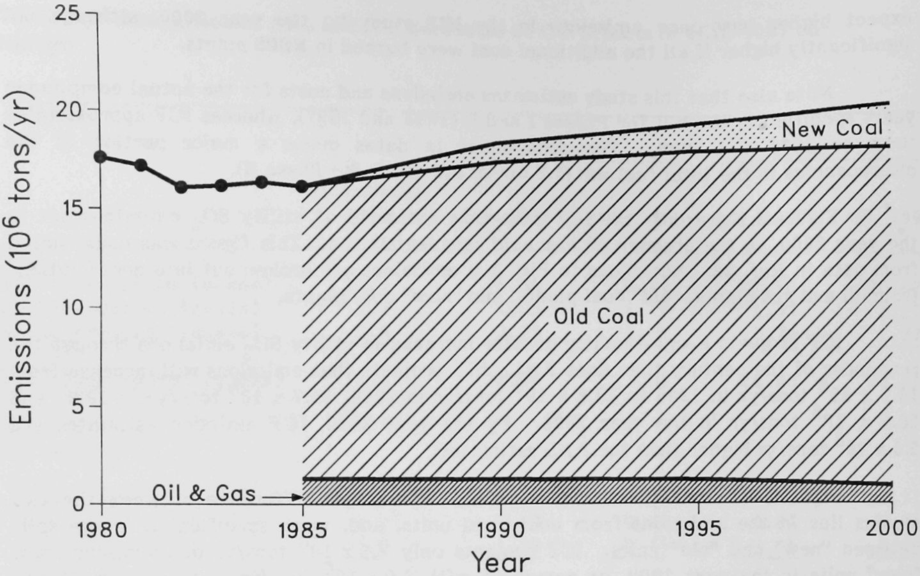

FIGURE 3.2 ICF Projections of Future Utility SO_2 Emission Trends

Since ICF's baseline emission estimates for Phase II are significantly higher than ANL's (16%), while fossil-fuel consumption estimates are only moderately higher (8%), average SO_2 emission rates (in pounds per million Btu) in the future will be higher in the ICF study. Higher average emission rates and higher absolute emissions imply that greater emission reductions are required to comply with H.R. 4567. ICF's slightly higher SO_2 emissions estimates in 2000 are the result of slightly higher total fossil-fuel consumption in that year as compared with ANL's estimate for 1997. Emission differences between the two studies may also arise from differences in regional electricity demand growth rates.

Figure 3.3 compares the effects of the bill on utility SO_2 emissions as calculated in the two studies, assuming that compliance is achieved at a constant rate. Although emission reductions are less in the ANL study, utility emissions after compliance are actually lower in the ANL study than in the ICF study because of the baseline anomaly. In the longer term, assuming identical energy and economic scenarios (nationally, regionally, and fuel mix), estimates for the two studies would converge at the point where all SIP plants are retired.

Differences between ANL and ICF estimates are readily explicable. They derive primarily from conflicting views of the way utility companies will respond to increased electricity demand in the future. Differences in emission reduction estimates are most likely not due to differences in model structure or operation, interpretation of H.R. 4567, or, for the most part, energy and economic forecasts.

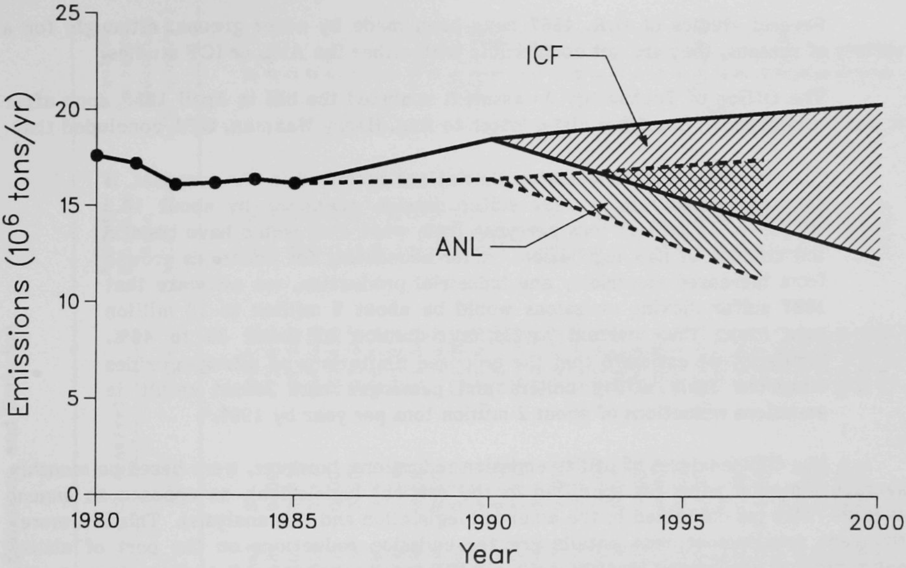

FIGURE 3.3 Comparison of Utility Emission Reductions Achieved by H.R. 4567 According to ICF and ANL Studies

Although ICF's emission reduction estimates are higher than ANL's, the two sets of emission control cost estimates of the least-cost solution are not dissimilar. The cost estimates for Phase I are both $\$0.7 \times 10^9$/yr. The ICF cost estimate for Phase II is $\$2.5 \times 10^9$/yr, as compared with the ANL estimate of $\$2.2 \times 10^9$/yr. Cost-effectiveness values are higher for the ANL estimates.

This may be explained by the fact that ICF consistently predicts greater fuel switching under least-cost control strategies than does ANL. The assumed availability of large amounts of low-sulfur coal in the East would tend to reduce control costs without affecting emissions greatly. This argument is supported by the ANL estimate of 19.6 GW of retrofit FGD capacity under Phase II of the bill, compared with only 4.1 GW in the ICF study.

For the default case, ICF predicts higher emission reductions and control costs than ANL. This is a result of greater utilization of retrofit FGD in the ICF study (40 GW vs. 28 GW under Phase II). It is not immediately apparent why the ICF model heavily favors fuel switching to meet a least-cost strategy but resorts to FGD to comply with a 1.2 lb/10^6 Btu ceiling at the unit level. One explanation is that ICF's model may include in its coal data base many eastern coals that are slightly above 1.2 lb/10^6 Btu but only a few coals below 1.2 lb/10^6 Btu. The coals below 1.2 lb/10^6 Btu are in heavy demand, thereby inflating their price. Some eastern units therefore are forced to import low-sulfur western coals and pay expensive transportation costs or scrub local high-sulfur coals.

Several studies of H.R. 4567 have been made by other groups, although, for a variety of reasons, they are not comparable with either the ANL or ICF studies.

The Office of Technology Assessment analyzed the bill in April 1986, soon after it was introduced.[26] In a transmittal letter to Rep. Henry Waxman, OTA concluded that

> "... the sulfur dioxide emission limitations specified in the proposal, if enacted, would reduce 1997 sulfur dioxide emissions by about 10.5 million to 11 million tons per year from what they would have been in the absence of new legislation. After accounting for emissions growth from increased electricity and industrial production, we estimate that 1997 sulfur dioxide emissions would be about 9 million to 10 million tons lower than current levels, a reduction of about 35 to 40%. Similarly, we estimate that the proposed limitations on nitrogen oxides emissions from utility boilers and passenger cars would result in emissions reductions of about 2 million tons per year by 1997."

The OTA analyses of utility emission reductions, however, were based on *monthly* average emission rates (as specified in the original legislation), as opposed to *annual* average rates (as contained in the amended legislation and this analysis). This is a more-stringent requirement that entails greater emission reductions on the part of utility companies. It also means that the ANL and ICF results cannot be directly compared with the OTA results.

Temple, Barker & Sloane, Inc., (TBS) prepared an analysis of H.R. 4567 for the Edison Electric Institute.[27] TBS calculated that the bill would achieve a reduction of 8.3×10^6 tons/yr in utility SO_2 emissions, relative to 1983-85 levels, excluding growth offsets. Control costs were estimated to be $\$5.4 \times 10^9$/yr levelized over a 20-yr period.

Again, the TBS analysis assumed monthly average emission rates, rather than annual, so results are not directly comparable. In addition, the Congressional Research Service[28] was critical of the TBS study on the grounds that the study chose assumptions that tended to bias the analysis towards overstating the potential adverse effects of the bill on the electric utility industry.

An analysis by the American Electric Power System[29] of the likely effects of the bill on its member companies also suggested somewhat extreme impacts that are not corroborated by the ANL or ICF studies.

3.2 STATE-LEVEL UTILITY SO_2 IMPACTS

Because the emission limitations under the Sikorski bill are averaged over all utility fossil-fuel consumption, it is necessary to project levels of consumption of coal, oil, and natural gas in each state, in order to be able to calculate emission reduction requirements. Table 3.3 shows utility consumption of coal, oil, and natural gas projected for 1993 using the NEPP-V estimates disaggregated to the state level by the ARAM model. The SO_2 emissions corresponding to these energy quantities are also shown. Using these data, statewide average emission rates can be calculated by dividing state-level utility SO_2 emissions by state-level fossil-fuel consumption. These average rates

TABLE 3.3 State-Level Estimates of Utility Fuel Consumption, SO_2 Emissions, and Emission Reductions Required by Phase I of the Sikorski Bill in 1993

State	Fuel Consumption (10^{15} Btu/yr)				SO_2 Emissions (10^3 tons/yr)				Average Emission Rate ($lb/10^6$ Btu)	Required Emission Reduction (10^3 tons/yr)
	Coal	Oil	Gas	Total	Coal	Oil	Gas	Total		
Alabama	0.571	0	0.001	0.572	501.130	0.043	0	501.173	1.753	0
Arizona	0.265	0.002	0.016	0.284	75.180	0.689	0.005	75.874	0.535	0
Arkansas	0.204	0.007	0.047	0.258	90.520	7.408	0.014	97.942	0.760	0
California	0.204	0.186	0.599	0.989	20.430	33.859	0.171	54.460	0.110	0
Colorado	0.334	0	0.009	0.343	107.520	0.116	0.003	107.639	0.628	0
Connecticut	0	0.147	0.016	0.163	0	47.636	0.004	47.640	0.585	0
Delaware	0.065	0.021	0.010	0.096	17.560	10.993	0.003	28.556	0.596	0
Florida	1.061	0.195	0.163	1.420	634.010	159.173	0.048	793.231	1.118	0
Georgia	0.677	0.002	0.003	0.682	719.990	1.552	0.001	721.543	2.117	39.729
Idaho	0	0.006	0.024	0.030	0	3.291	0.007	3.298	0.218	0
Illinois	0.719	0.016	0.010	0.746	1,025.440	5.762	0.003	1,031.205	2.766	285.650
Indiana	1.006	0.001	0.003	1.010	1,556.490	0.168	0.001	1,556.659	3.084	547.018
Iowa	0.221	0.001	0.004	0.226	227.100	0.092	0.001	227.193	2.008	0.954
Kansas	0.262	0.001	0.042	0.304	83.620	0.410	0.013	84.043	0.552	0
Kentucky	0.796	0	0.001	0.797	696.350	0.062	0	696.412	1.747	0
Louisiana	0.252	0.011	0.215	0.478	116.040	4.637	0.062	120.739	0.505	0
Maine	0	0.018	0.045	0.063	0	15.086	0.012	15.098	0.476	0
Maryland	0.328	0.018	0.003	0.349	287.330	12.607	0.001	299.938	1.718	0
Massachusetts	0.111	0.304	0.033	0.448	27.450	189.449	0.010	216.090	0.968	0
Michigan	0.709	0.017	0.008	0.735	603.010	6.027	0.004	609.041	1.657	0
Minnesota	0.377	0.002	0.006	0.385	176.840	1.039	0.002	177.881	0.924	0
Mississippi	0.101	0.008	0.044	0.153	93.080	10.084	0.013	103.177	1.349	0
Missouri	0.632	0.002	0.007	0.641	1,170.690	0.671	0.002	1,171.363	3.656	530.656
Montana	0.110	0	0.001	0.111	35.370	0.007	0	35.377	0.636	0
Nebraska	0.120	0.001	0.007	0.129	58.550	0.472	0.002	59.024	0.918	0
Nevada	0.192	0	0.011	0.203	56.760	0.031	0.003	56.794	0.559	0
New Hampshire	0.048	0.005	0.001	0.054	53.090	4.670	0	57.760	2.140	3.786
New Jersey	0.201	0.056	0.122	0.379	112.490	14.993	0.035	127.518	0.673	0
New Mexico	0.285	0.001	0.016	0.302	66.310	0.149	0.005	66.464	0.440	0
New York	0.513	0.221	0.124	0.859	291.260	146.143	0.036	437.439	1.019	0
N. Carolina	0.736	0.001	0.003	0.740	458.800	0.112	0.001	458.913	1.241	0
N. Dakota	0.165	0	0	0.165	84.490	0.010	0	84.500	1.023	0

TABLE 3.3 (Cont'd)

State	Fuel Consumption (10^{15} Btu/yr)				SO_2 Emissions (10^3 tons/yr)				Average Emission Rate ($lb/10^6$ Btu)	Required Emission Reduction (10^3 tons/yr)
	Coal	Oil	Gas	Total	Coal	Oil	Gas	Total		
Ohio	1.312	0.003	0.005	1.319	2,033.720	1.169	0.001	2,034.890	3.084	715.428
Oklahoma	0.291	0.002	0.280	0.572	126.190	0.178	0.080	126.448	0.442	0
Oregon	0.109	0.002	0	0.111	12.620	0.255	0	12.875	0.231	0
Pennsylvania	1.012	0.020	0.005	1.037	1,221.320	7.744	0.001	1,229.065	2.370	191.961
Rhode Island	0	0.018	0.011	0.029	0	8.405	0.003	8.408	0.589	0
S. Carolina	0.250	0.003	0.003	0.256	216.420	3.581	0.001	220.002	1.721	0
S. Dakota	0.045	0	0.001	0.046	29.250	0.061	0	29.311	1.264	0
Tennessee	0.630	0.001	0.001	0.632	764.550	0.203	0	764.753	2.419	132.427
Texas	1.826	0.003	1	2.829	806.800	0.924	0.252	807.976	0.571	0
Utah	0.186	0	0.001	0.188	57.490	0.032	0	57.522	0.613	0
Vermont	0.015	0.002	0.008	0.025	3.650	0.474	0.002	4.126	0.334	0
Virginia	0.373	0.037	0.003	0.413	208.340	34.258	0.001	242.599	1.174	0
Washington	0.080	0	0	0.080	40.090	0.077	0	40.167	0.999	0
W. Virginia	0.756	0	0	0.756	955.550	0.075	0	955.625	2.529	200.013
Wisconsin	0.367	0.001	0.007	0.374	367.560	0.313	0.002	367.875	1.965	0
Wyoming	0.272	0	0	0.272	74.470	0.022	0	74.492	0.547	0
Total	18.790	1.342	2.919	23.053	16,364.920	735.212	0.808	17,100.940	1.496	2,647.622

Values may not sum due to independent rounding.

are then compared to the mandatory rate of 2.0 lb/10^6 Btu specified under Phase I of the bill.

The inclusion of oil and natural gas consumption into the emission rate equation results in lower average rates than when only coal consumption is considered. When total fossil-fuel consumption is included in the equation, only ten states have average rates greater than 2.0 lb/10^6 Btu. The five states with the highest average emission rates are: Missouri (3.66 lb/10^6 Btu), Indiana (3.08 lb/10^6 Btu), Ohio (3.08 lb/10^6 Btu), Illinois (2.77 lb/10^6 Btu), and West Virginia (2.53 lb/10^6 Btu). Table 3.3 completes the picture by presenting the emission reductions that would be necessary to reduce emissions in the ten states to an average rate of 2.0 lb/10^6 Btu.

In a similar way, Table 3.4 calculates emission reductions necessary to achieve an average emission rate of 1.2 lb/10^6 Btu by 1997. Seventeen states are affected by this more-stringent requirement. Again, midwestern states that burn high-sulfur coal are affected the most.

The costs of achieving these emission reductions were calculated with the AIRCOST model, according to the least-cost methodology described in Sec. 2.1.2. Table 3.5 summarizes the state-level emission reductions and control costs after full implementation of the bill in 1997.

Also shown in Table 3.5, for comparison, is the equivalent least-cost strategy to achieve a total national emission reduction of 6.1 x 10^6 tons/yr, assuming full interstate trading. The least-cost strategy costs \$2.0 x 10^9/yr, as compared with the Sikorski bill cost of \$2.2 x 10^9/yr. This difference is small compared to similar comparisons made with other bills that have been studied. The reason for this is that H.R. 4567 is a cost-effective bill: it allows intrastate trading, it does not mandate the use of retrofit control technology, and in general its prescriptions require the majority of emission reductions in those states that offer the cheapest control options.

It should be noted that the levels of emission reduction required by the bill and the levels leading to the least-cost solution are similar for those states requiring large reductions. For example, Ohio would be required to reduce its utility SO_2 emissions by 1.22 x 10^6 tons/yr under the bill and by 1.25 x 10^6 tons/yr under the interstate trading strategy.

In general, intrastate trading and interstate trading solutions do not differ greatly when only moderate total SO_2 reductions are required (less than about 8 x 10^6 tons/yr). Large cost differences between strategies usually result when one strategy requires significant additional FGD capacity and the other does not. For most freedom-of-choice strategies (such as H.R. 4567), scrubbing is minimal for moderate levels of emission reduction. In this analysis, H.R. 4567 would result in an additional 20 GW of FGD capacity, while the interstate trading solution would require 12 GW.

Table 3.6 identifies those states that are projected to install FGD systems under Phases I and II of the Sikorski bill. The 8 GW of FGD capacity under Phase I would be installed in just three states: Pennsylvania, Indiana, and Missouri. Under Phase II, Pennsylvania and Indiana would require the largest retrofit capacity. Note that the

TABLE 3.4 State-Level Estimates of Utility Fuel Consumption, SO_2 Emissions, and Emission Reductions Required by Phase II of the Sikorski Bill in 1997

State	Fuel Consumption (10^{15} Btu/yr)				SO_2 Emissions (10^3 tons/yr)				Average Emission Rate ($lb/10^6$ Btu)	Required Emission Reduction (10^3 tons/yr)
	Coal	Oil	Gas	Total	Coal	Oil	Gas	Total		
Alabama	0.620	0	0.001	0.622	509.350	0.041	0	509.391	1.639	136.443
Arizona	0.285	0.002	0.016	0.303	77.120	0.669	0.005	77.794	0.514	0
Arkansas	0.228	0.007	0.045	0.280	101.200	7.150	0.013	108.363	0.774	0
California	0.184	0.180	0.589	0.953	18.420	2.381	0.168	50.969	0.107	0
Colorado	0.372	0	0.009	0.381	111.280	0.112	0.003	111.395	0.585	0
Connecticut	0	0.141	0.016	0.157	0	5.954	0.004	45.958	0.587	0
Delaware	0.072	0.020	0.010	0.102	19.400	0.601	0.003	30.004	0.588	0
Florida	1.186	0.188	0.160	1.534	665.180	3.524	0.047	818.751	1.067	0
Georgia	0.755	0.002	0.003	0.761	739.330	1.508	0.001	740.839	1.948	284.473
Idaho	0	0.006	0.024	0.030	0	3.173	0.007	3.180	0.213	0
Illinois	0.766	0.015	0.010	0.791	1,036.570	5.556	0.003	1,042.129	2.636	567.647
Indiana	1.102	0.001	0.003	1.106	1,580.490	0.161	0.001	1,580.652	2.859	917.307
Iowa	0.269	0.001	0.004	0.274	239.060	0.088	0.001	239.149	1.746	74.751
Kansas	0.290	0.001	0.041	0.332	95.890	0.395	0.013	96.298	0.581	0
Kentucky	0.839	0	0.001	0.840	706.800	0.060	0	706.860	1.683	202.754
Louisiana	0.296	0.010	0.213	0.519	135.230	4.462	0.062	139.754	0.538	0
Maine	0	0.017	0.045	0.062	0	4.547	0.012	14.599	0.473	0
Maryland	0.364	0.017	0.003	0.384	303.940	2.279	0.001	316.220	1.646	85.659
Massachusetts	0.124	0.293	0.033	0.449	30.710	2.594	0.010	213.314	0.950	0
Michigan	0.788	0.016	0.008	0.813	640.200	5.799	0.004	646.003	1.590	158.349
Minnesota	0.419	0.002	0.006	0.427	186.200	1.002	0.002	187.204	0.876	0
Mississippi	0.104	0.007	0.043	0.154	93.480	9.724	0.013	103.217	1.341	10.855
Missouri	0.697	0.002	0.007	0.706	1,199.440	0.647	0.002	1,200.089	3.400	776.541
Montana	0.101	0	0.001	0.102	32.300	0.007	0	32.307	0.631	0
Nebraska	0.131	0.001	0.007	0.139	59.290	0.455	0.002	59.747	0.860	0
Nevada	0.242	0	0.011	0.253	61.730	0.030	0.003	61.763	0.489	0
New Hampshire	0.048	0.005	0.001	0.054	53.090	4.503	0.000	57.593	2.134	25.214
New Jersey	0.224	0.054	0.120	0.398	118.250	4.665	0.035	132.950	0.668	0
New Mexico	0.324	0.001	0.016	0.341	70.190	0.144	0.005	70.339	0.413	0
New York	0.573	0.213	0.122	0.908	306.180	1.079	0.035	447.294	0.985	0
N. Carolina	0.825	0.001	0.003	0.828	480.960	0.108	0.001	481.069	1.161	0
N. Dakota	0.182	0	0	0.182	88.260	0.010	0	88.270	0.970	0

TABLE 3.4 (Cont'd)

State	Fuel Consumption (10^{15} Btu/yr)				SO_2 Emissions (10^3 tons/yr)				Average Emission Rate (lb/10^6 Btu)	Required Emission Reduction (10^3 tons/yr)
	Coal	Oil	Gas	Total	Coal	Oil	Gas	Total		
Ohio	1.461	0.003	0.005	1.468	2,095.000	1.131	0.001	2,096.133	2.855	1,215.151
Oklahoma	0.325	0.002	0.275	0.602	141.090	0.172	0.079	141.341	0.470	0
Oregon	0.122	0.002	0	0.124	13.860	0.245	0	14.105	0.228	0
Pennsylvania	1.054	0.019	0.005	1.078	1,238.220	7.619	0.001	1,245.840	2.311	599.051
Rhode Island	0	0.017	0.008	0.025	0	8.104	0.002	8.106	0.651	0
S. Carolina	0.277	0.003	0.003	0.283	223.230	3.453	0.001	226.684	1.603	56.969
S. Dakota	0.049	0	0.001	0.051	30.210	0.058	0	30.268	1.197	0
Tennessee	0.705	0.001	0.001	0.707	783.260	0.195	0	783.455	2.216	359.224
Texas	2.026	0.003	0.982	3.011	894.770	0.891	0.248	895.909	0.595	0
Utah	0.206	0	0.001	0.207	59.430	0.031	0	59.461	0.574	0
Vermont	0.016	0.002	0.008	0.026	4.070	0.457	0.002	4.529	0.345	0
Virginia	0.417	0.035	0.003	0.455	227.970	2.958	0.001	260.929	1.148	0
Washington	0.080	0	0	0.080	40.090	0.075	0	40.165	0.999	0
W. Virginia	0.815	0	0	0.815	970.470	0.072	0	970.542	2.381	481.386
Wisconsin	0.408	0.001	0.007	0.416	374.330	0.302	0.002	374.634	1.803	125.286
Wyoming	0.302	0	0	0.302	76.580	0.021	0	76.601	0.507	0
Total	20.672	1.291	2.869	24.832	16,932.121	709.212	0.794	17,642.127	1.428	6,077.061

Values may not sum due to independent rounding.

TABLE 3.5 State-Level Impacts of H.R. 4567 and Its Least-Cost Alternative for the Utility in 1997

State	Bill as Formulated: Emission Reduction[a] (10^3 tons/yr)	Bill as Formulated: Control Cost[b] ($\$10^6$/yr)	Interstate Trading Alternative: Emission Reduction[a] (10^3 tons/yr)	Interstate Trading Alternative: Control Cost[b] ($\$10^6$/yr)
Alabama	136	20	208	33
Colorado	-	-	11	1
Florida	-	-	232	88
Georgia	284	83	344	112
Illinois	568	143	633	170
Indiana	917	415	833	367
Iowa	75	4	143	11
Kansas	-	-	4	2
Kentucky	203	93	155	61
Maryland	86	57	-	-
Michigan	158	82	52	16
Minnesota	-	-	34	1
Mississippi	11	4	48	15
Missouri	777	245	852	284
Montana	-	-	3	0
Nebraska	-	-	10	4
New Hampshire	25	15	-	-
New Jersey	-	-	12	4
New York	-	-	7	1
Ohio	1,215	328	1,246	344
Pennsylvania	599	368	215	104
S. Carolina	57	46	-	-
Tennessee	359	122	407	146
Texas	-	-	2	1
Utah	-	-	10	1
Virginia	-	-	11	4
W. Virginia	481	165	523	187
Wisconsin	125	35	83	6
Totals	6,078	2,225	6,078	1,960

[a]Emissions of SO_2 in 1997 without H.R. 4567, minus the levels allowed in 1997 under the bill.

[b]In 1985 dollars.

TABLE 3.6 Utility Retrofit FGD Capacity Requirements to Comply with H.R. 4567

State	Phase I Number	Phase I Capacity (MW)	Phase II Number	Phase II Capacity (MW)
Alabama	0	0	0	0
Georgia	0	0	0	0
Illinois	0	0	2	1,208
Indiana	6	2,991	11	4,805
Iowa	0	0	0	0
Kentucky	0	0	0	0
Maryland	0	0	2	1,112
Michigan	0	0	2	1,500
Mississippi	0	0	0	0
Missouri	3	1,490	3	1,490
New Hampshire	0	0	1	337
Ohio	0	0	0	0
Pennsylvania	8	3,580	11	7,420
S. Carolina	0	0	0	0
Tennessee	0	0	0	0
W. Virginia	0	0	1	210
Wisconsin	0	0	3	1,584
Total	17	8,061	36	19,666

degrees of FGD usage is not proportional to the amount of emission reduction required. Several states, such as Ohio and Tennessee, which have large reductions, are projected by the model to achieve all of their emission reductions through fuel switching under a least-cost intrastate trading interpretation. Of course, some states may choose to forgo some of the economic benefits of fuel switching in order to protect existing high-sulfur coal markets, as discussed in Sec. 6. If such were to be the case, compliance costs for those states would be greater, as would the amounts of FGD capacity installed.

Cost-effectiveness values for achieving the mandated emission reductions vary significantly from state to state. Table 3.7 shows the estimates for Phase I of the bill. For states requiring significant levels of emission reduction, cost-effectiveness ranges from a low value of $151/ton in Georgia to a high value of $482/ton in Pennsylvania. The average for all states is $279/ton.

Table 3.8 shows similar estimates for Phase II of the bill. Due to the greater emission reduction, cost-effectiveness values are higher and vary more widely than for Phase I. The lowest value is $49/ton in Iowa, the highest value is $808/ton in South Carolina, and the average is for all states is $366/ton.

TABLE 3.7 State-Level Cost-Effectiveness for Utility Compliance with Phase I of the Sikorski Bill (1993)

State	SO_2 Emission Reductions (10^3 Tons/yr) Coal	Oil	Total	Control Costs (10^6 1985 \$/yr) Coal	Oil	Total	Cost-Effectiveness (1985 \$/ton)
Georgia	40	0	40	6	0	6	151
Illinois	286	0	286	50	0	50	175
Indiana	547	0	547	221	0	221	405
Iowa	1	0	1	0	0	0	49
Missouri	531	0	531	155	0	155	292
New Hampshire	0	4	4	0	6	6	1,558
Ohio	715	0	715	120	0	120	168
Pennsylvania	192	0	192	92	0	92	482
Tennessee	132	0	132	44	0	44	331
W. Virginia	200	0	200	45	0	45	224
Total	2,644	4	2,648	734	6	734	279

3.3 UTILITY NO_x IMPACTS

The AIRCOST modeling system was also used to estimate the emission reductions necessary to achieve a statewide average NO_x emission rate of 0.6 lb/10^6 Btu by 1997, according to the methodology described in Sec. 2. Table 3.9 restates the 1997 fuel estimates of Table 3.4 and shows projected NO_x emissions from coal, oil, and gas combustion in utility power plants. Average NO_x emission rates in each state were then calculated.

Because the emission rate is averaged over all fossil-fuel consumption, those coal-burning states that also consume large quantities of natural gas (e.g., New York, New Jersey, Texas) gain an advantage in achieving a statewide ceiling of 0.6 lb/10^6 Btu. Table 3.9 shows that 33 states are projected to have average emission rates in excess of 0.6 lb/10^6 Btu in 1997. The necessary NO_x emission reductions to comply with this provision are estimated to be 1.3 x 10^6 tons/yr nationwide. Illinois, Indiana, Kentucky, and West Virginia would each be expected to achieve reductions of greater than 100,000 tons/yr.

The control costs necessary to achieve this level of NO_x emission reduction are estimated to be about \$400 x 10^6/yr, as shown in Table 3.10. The average cost would be about \$700/ton of NO_x reduced. By far the greatest proportion of the cost burden would be borne by Illinois (about 58%). This is because of the relatively large proportion of cyclone boilers in that state, which are not adaptable to any of the more-conventional combustion modification NO_x controls. It is probable that very costly selective catalytic reduction of NO_x in the flue gases would be necessary.

TABLE 3.8 State-Level Cost-Effectiveness for Utility Compliance with Phase II of the Sikorski Bill (1997)

State	SO_2 Emission Reductions (10^3 tons/yr)			Control Costs (10^6 1985 $/yr)			Cost-Effectiveness (1985 $/ton)
	Coal	Oil	Total	Coal	Oil	Total	
Alabama	136	0	136	19	0	19	143
Georgia	284	0	284	83	0	83	292
Illinois	568	0	568	143	0	143	252
Indiana	917	0	917	415	0	415	452
Iowa	75	0	75	4	0	4	49
Kentucky	203	0	203	93	0	93	456
Maryland	83	2	86	55	1	56	665
Michigan	158	0	158	81	0	81	513
Mississippi	8	2	11	2	0	3	283
Missouri	777	0	777	245	0	245	316
New Hampshire	25	0	25	15	0	15	602
Ohio	1,215	0	1,215	328	0	328	270
Pennsylvania	599	0	599	369	0	369	616
S. Carolina	57	1	57	46	0	47	808
Tennessee	359	0	359	122	0	122	340
W. Virginia	481	0	481	165	0	165	343
Wisconsin	125	0	125	35	0	35	279
Total	6,072	6	6,078	2,221	2	2,225	366

3.4 INDUSTRIAL BOILER IMPACTS

The Sikorski bill requires that states reduce emissions from industrial boilers to statewide average emission rates of 1.2 lb/10^6 Btu (SO_2) and 0.6 lb/10^6 Btu (NO_x) by 1997. The emission rates are to be averaged over all nonutility fossil-fuel consumption in steam-generating units. These requirements are equivalent to the Phase II requirements for utility boilers.

Using the methodology described in Sec. 2, average SO_2 and NO_x emission rates in 1997 were calculated on the basis of projected industrial fossil-fuel consumption. Table 3.11 presents this information at the state level.

Only 14 states would be required to reduce industrial boiler emissions to achieve a statewide average rate of 1.2 lb/10^6 Btu in 1997. The total reduction necessary would

TABLE 3.9 State-Level Estimates of Utility Fuel Consumption, NO_x Emissions, and Emission Reductions Required by Phase II of the Sikorski Bill in 1997

State	Fuel Consumption (10^{15} Btu/yr)				NO_x Emission (10^3 tons/yr)				Average Emission Rate (lb/10^6 Btu)	Required Emission Reduction (10^3 tons/yr)
	Coal	Oil	Gas	Total	Coal	Oil	Gas	Total		
Alabama	0.620	0	0.001	0.622	217.530	0.043	0.171	217.744	0.701	31.272
Arizona	0.285	0.002	0.016	0.303	105.470	0.382	3.014	108.866	0.719	18.057
Arkansas	0.228	0.007	0.045	0.280	77.830	1.593	9.868	89.291	0.637	5.238
California	0.184	0.180	0.589	0.953	63.040	27.057	81.224	171.321	0.360	0
Colorado	0.372	0	0.009	0.381	137.720	0.103	2.010	139.833	.735	25.668
Connecticut	0	0.141	0.016	0.157	0.000	21.750	3.374	25.124	0.321	0
Delaware	0.072	0.020	0.010	0.102	24.010	4.458	1.531	29.999	0.588	0
Florida	1.186	0.188	0.160	1.534	353.240	37.358	31.773	422.372	0.551	0
Georgia	0.755	0.002	0.003	0.761	274.050	0.357	0.603	275.010	0.723	46.827
Idaho	0	0.006	0.024	0.030	0	1.377	4.739	6.116	0.410	0
Illinois	0.766	0.015	0.010	0.791	410.350	2.816	2.044	415.210	1.050	177.969
Indiana	1.102	0.001	0.003	1.106	480.840	0.234	0.594	481.668	0.871	149.996
Iowa	0.269	0.001	0.004	0.274	115.450	0.191	0.886	116.527	0.851	34.327
Kansas	0.290	0.001	0.041	0.332	108.810	0.295	9.262	118.367	0.714	18.903
Kentucky	0.839	0	0.001	0.840	369.990	0.064	0.217	370.271	0.881	118.218
Louisiana	0.296	0.010	0.213	0.519	91.510	1.925	41.777	135.212	0.521	0
Maine	0	0.017	0.045	0.062	0	3.979	10.320	14.299	0.464	0
Maryland	0.364	0.017	0.003	0.384	120.320	3.978	0.605	124.903	0.650	9.620
Massachuetts	0.124	0.293	0.033	0.449	27.610	57.091	7.005	91.706	0.408	0
Michigan	0.788	0.016	0.008	0.813	312.950	3.445	2.822	319.217	0.786	75.390
Minnesota	0.419	0.002	0.006	0.427	108.790	0.404	1.273	110.467	0.517	0
Mississippi	0.104	0.007	0.043	0.154	39.690	1.199	8.634	49.523	0.643	3.345
Missouri	0.697	0.002	0.007	0.706	289.350	0.572	1.683	291.605	0.826	79.834
Montana	0.101	0	0.001	0.102	37.430	0.029	0.296	37.755	0.738	7.052
Nebraska	0.131	0.001	0.007	0.139	50.300	0.242	1.514	52.056	0.749	10.357
Nevada	0.242	0	0.011	0.253	81.650	0.020	2.205	83.875	0.664	8.104
New Hampshire	0.048	0.005	0.001	0.054	22.610	1.029	0.115	23.754	0.880	7.565
New Jersey	0.224	0.054	0.120	0.398	82.010	10.922	23.514	116.446	0.585	0

TABLE 3.9 (Cont'd)

State	Fuel Consumption (10^{15} Btu/yr)				NO_x Emission (10^3 tons/yr)				Average Emission Rate (lb/10^6 Btu)	Required Emission Reduction (10^3 tons/yr)
	Coal	Oil	Gas	Total	Coal	Oil	Gas	Total		
New Mexico	0.324	0.001	0.016	0.341	113.390	0.147	3.190	116.727	0.685	14.471
New York	0.573	0.213	0.122	0.908	148.210	46.132	20.396	214.738	0.473	0
N. Carolina	0.825	0.001	0.003	0.828	280.180	0.234	0.573	280.987	0.678	32.465
N. Dakota	0.182	0	0	0.182	58.860	0.020	0.034	58.914	0.648	4.332
Ohio	1.461	0.003	0.005	1.468	536.260	0.788	0.923	537.971	0.733	97.480
Oklahoma	0.325	0.002	0.275	0.602	103.260	0.373	48.725	152.358	0.507	0
Oregon	0.122	0.002	0	0.124	38.160	0.451	0	38.611	0.623	1.444
Pennsylvania	1.054	0.019	0.005	1.078	372.110	4.429	0.938	377.477	0.700	54.082
Puerto Rico	0	0.017	0.008	0.025	0	3.909	1.795	5.704	0.458	0
S. Carolina	0.277	0.003	0.003	0.283	104.700	0.735	0.612	106.047	0.750	21.190
S. Dakota	0.049	0	0.001	0.051	17.310	0.085	0.247	17.642	0.697	2.465
Tennessee	0.705	0.001	0.001	0.707	224.170	0.170	0.256	224.596	0.635	12.481
Texas	2.026	0.003	0.982	3.011	631.320	0.759	173.950	806.029	0.535	0
Utah	0.206	0	0.001	0.207	72.160	0.041	0.337	72.538	0.700	10.395
Vermont	0.016	0.002	0.008	0.026	2.260	0.496	1.676	4.432	0.338	0
Virginia	0.417	0.035	0.003	0.455	146.600	7.339	0.531	154.470	0.680	18.094
Washington	0.080	0	0	0.080	24.060	0.019	0.041	24.120	0.600	0.009
W. Virginia	0.815	0	0	0.815	346.180	0.105	0.020	346.305	0.850	101.727
Wisconsin	0.408	0.001	0.007	0.416	166.330	0.337	1.564	168.231	0.810	43.557
Wyoming	0.302	0	0	0.302	132.200	0.021	0.020	132.241	0.875	41.527
Total	20.672	1.291	2.869	24.833	7520.271	249.503	508.903	8278.678	0.667	1283.460

TABLE 3.10 Utility Costs for Complying with Phase II Requirements for Nitrogen Oxides

State	Emission Reduction (10^3 tons/yr)	Control Costs (10^6 1985 \$/yr)	Average Cost (\$/ton)
Alabama	31.72	2.54	80.00
Arizona	18.06	1.50	82.86
Arkansas	5.24	1.00	190.81
Colorado	25.67	3.19	124.38
Georgia	46.83	5.15	110.46
Illinois	177.97	229.44	1,289.22
Indiana	150.00	29.17	194.18
Iowa	34.33	6.09	177.36
Kansas	18.90	3.75	198.48
Kentucky	118.22	19.33	163.54
Maryland	9.62	0.77	80.00
Michigan	75.39	10.92	144.85
Mississippi	3.35	0.27	80.00
Missouri	79.83	13.20	165.40
Montana	7.05	1.16	164.50
Nebraska	10.36	4.33	418.33
Nevada	8.10	0.65	80.0
New Hampshire	7.57	9.47	1,251.03
New Mexico	14.47	1.16	200.00
N. Carolina	32.47	2.60	80.00
N. Dakota	4.33	0.35	80.00
Ohio	97.48	8.72	89.43
Oregon	1.44	0.12	80.00
Pennsylvania	54.08	4.33	80.00
S. Carolina	21.19	2.39	112.88
S. Dakota	2.47	0.20	80.00
Tennessee	12.48	1.00	80.00
Utah	10.40	0.83	80.00
Virginia	18.09	2.89	159.84
W. Virginia	101.73	13.56	133.25
Wisconsin	43.56	5.86	134.53
Wyoming	41.53	7.32	176.18
Total	1,283.45	393.26	706.41

TABLE 3.11 State-Level Estimates of Fuel Consumption, Emissions, and Emissions Reductions Necessary to Comply with the Sikorski Bill Requirements for Industrial Boilers in 1997

State	Fuel Consumption (10^{15} Btu/yr)	SO_2 Emissions (10^3 tons/yr)	SO_2 Emission Rate (lb/10^6 Btu)	SO_2 Emission Reductions (10^3 tons/yr)	NO_x Emissions (10^3 tons/yr)	NO_x Emission Rate (lb/10^6)
Alabama	0.1755	78.50	0.954	0	27.00	0.308
Arizona	0.0300	5.50	0.366	0	3.00	0.200
Arkansas	0.0780	51.50	1.320	4.7	11.50	0.294
California	0.2585	51.50	0.398	0	28.50	0.220
Colorado	0.0610	11.50	0.378	0	10.00	0.328
Connecticut	0.0350	6.50	0.372	0	3.50	0.200
Delaware	0.0265	10.00	0.754	0	4.00	0.302
Florida	0.1095	38.50	0.704	0	11.00	0.200
Georgia	0.1690	69.00	0.816	0	22.50	0.266
Idaho	0.0225	6.00	0.534	0	3.50	0.312
Illinois	0.2970	123.00	0.828	0	41.00	0.276
Indiana	0.1470	125.00	1.700	36.8	29.00	0.394
Iowa	0.0770	46.50	1.208	0.3	13.50	0.350
Kansas	0.0360	31.00	1.722	9.4	5.50	0.306
Kentucky	0.0635	25.00	0.788	0	10.00	0.314
Louisiana	0.2700	184.00	1.362	22.0	36.50	0.270
Maine	0.0450	29.00	1.288	2.0	7.00	0.312
Maryland/DC	0.0845	16.00	0.378	0	11.00	0.260
Massachusetts	0.0590	18.50	0.628	0	7.00	0.238
Michigan	0.2380	98.00	0.824	0	49.50	0.416
Minnesota	0.0700	25.50	0.728	0	9.50	0.272
Mississippi	0.0160	5.00	0.626	0	2.00	0.250
Missouri	0.0470	29.50	1.256	1.3	6.50	0.276
Montana	0.0125	4.50	0.720	0	1.50	0.240
Nebraska	0.0225	9.50	0.844	0	3.00	0.266
Nevada	0.0060	2.00	0.666	0	1.00	0.334
New Hampshire	0.0030	2.00	1.334	0.2	0	0

TABLE 3.11 (Cont'd)

State	Fuel Consumption (10^{15} Btu/yr)	SO_2 Emissions (10^3 tons/yr)	SO_2 Emission Rate (lb/10^6 Btu)	SO_2 Emission Reductions (10^3 tons/yr)	NO_x Emissions (10^3 tons/yr)	NO_x Emission Rate (lb/10^6)
New Jersey	0.1120	29.00	0.518	0	13.00	0.232
New Mexico	0.0465	0	0	0	4.00	0.172
New York	0.1640	95.00	1.158	0	30.00	0.366
N. Carolina	0.1915	110.00	1.148	0	32.50	0.340
N. Dakota	0.0060	3.50	1.166	0	1.00	0.334
Ohio	0.2870	244.50	1.704	72.3	65.50	0.456
Oklahoma	0.1005	3.50	0.070	0	10.00	0.200
Oregon	0.0765	20.00	0.522	0	8.50	0.222
Pennsylvania	0.2640	127.50	0.966	0	56.50	0.428
Rhode Island	0.0050	1.00	0.400	0	0	0
S. Carolina	0.1295	112.50	1.738	34.8	25.50	0.394
S. Dakota	0.0020	1.00	1.000	0	0	0
Tennessee	0.1550	104.00	1.342	11.0	30.50	0.394
Texas	0.7360	199.00	0.540	0	100.00	0.272
Utah	0.0475	18.00	0.758	0	9.00	0.378
Vermont	0.0030	2.00	1.334	0.2	0.50	0.334
Virginia	0.1080	68.00	1.260	3.2	25.00	0.462
Washington	0.0885	18.50	0.418	0	8.50	0.192
W. Virginia	0.1040	58.50	1.126	0	27.50	0.528
Wisconsin	0.1330	100.50	1.512	20.7	25.00	0.376
Wyoming	0.0630	34.50	1.096	0	9.00	0.286
Total	5.2820	2453.00	43.272	218.9	839.50	13.770

be only about 220,000 tons/yr. All states would be below 0.6 lb/10^6 Btu of NO_x, due to the greater use of oil and natural gas in industrial operations, such that no further NO_x reductions would be necessary.

Due to the unavailability of a reliable control cost model that has the capability of simulating industrial boiler behavior on a national scale, no estimate is presented here of the costs to achieve the 200,000 tons/yr of SO_2 reductions from industrial boilers.

3.5 TRANSPORTATION IMPACTS

The Sikorski bill requires more-stringent emission controls for the transportation sector. If the bill were enacted, NO_x emission limits for passenger cars and certain classes of light-duty trucks would be lowered, and the hydrocarbon (HC) standards for light-duty trucks would be substantially tightened. There would also be a regulation limiting the amount of sulfur contained in diesel fuel, and evaporative HC controls would be required. Transportation emission limits will affect all states in the United States, but its effects will be phased in over a longer time period as new vehicles are placed in operation. This is in contrast to H.R. 4567 boiler regulations, which only affect certain high-emitting states.

3.5.1 NO_x Emission Regulations

NO_x emission limits proposed in H.R. 4567 would affect passenger cars and light-duty trucks weighing between 3,750 and 6,000 lb. A comparison of current "final" standards and standards proposed by the bill is shown in Table 3.12. The standard for passenger cars would be lowered from 1.0 to 0.7 g/mi, and for light-duty trucks weighing between 3,750 and 6,000 lb, the standard would be lowered from 1.7 to 1.2 g/mi.

Requiring more-stringent NO_x controls will lead to higher deterioration rates for NO_x control systems, as compared to control systems that comply with current standards. Automakers will therefore have to reduce the zero-mile average NO_x emission rate considerably below the proposed standard to ensure that vehicles will be in compliance with the mandate after operating for 50,000 miles. This lower zero-mile rate will have relatively high parasitic losses resulting in lower fuel economy. Simultaneously achieving carbon dioxide (CO_2) and HC certification is also more difficult when stringently controlling NO_x emissions. Therefore, additional control measures for these pollutants may be necessitated.

Emission reduction estimates relative to a business-as-usual scenario are shown in Table 3.13. Emission reductions attributed to the bill are very modest in 1990, but increase rapidly as the percentage of vehicles regulated under the bill also increases. ANL modeling results presented in Table 3.13 are in agreement with estimates made by the Office of Technology Assessment (OTA).[26] OTA estimates that the NO_x emission limit for passenger cars, as specified by H.R. 4567, will reduce emissions by approximately 300,000 tons/yr relative to business-as-usual emission projections. As discussed in Chapter 2, control costs are estimated to be approximately \$1,000 per ton of NO_x removed.

TABLE 3.12 Comparison of Current NO_x Emission Standards for Vehicles and More-Stringent Standards Proposed in H.R. 4567

Vehicle Class	Effective Year		Standard (g/mi)	
	Current	H.R. 4567	Current	H.R. 4567
Passenger cars	1981	1989	1.0	0.7
Light-duty trucks under 3,750 lb	1988	1988	1.2	1.2
Light-duty trucks from 3,750 lb to 6,000 lb	1988	1988	1.7	1.2
Light-duty trucks over 6,000 lb	1988	1988	1.7	1.7

TABLE 3.13 Estimates of NO_x Emission Reductions Associated with H.R. 4567

Year	NO_x Emission Reductions (10^3 tons/yr)		
	Passenger Cars	Light-Duty Trucks	Total
1990	63.9	1.7	65.6
1995	249.5	6.3	255.8
1997[a]	299.6	7.6	307.2
2000	354.3	9.0	363.3
2005	407.4	10.4	417.8
2010	435.7	11.1	446.8
2015	453.0	11.5	464.5
2020	470.4	11.9	482.3
2025	484.5	12.3	497.8
2030	498.5	12.8	511.3

[a]Year for which OTA estimated NO_x emission reductions associated with H.R 4567.

3.5.2 Hydrocarbons

Proposed HC emission limits for light-duty trucks are significantly more stringent than the current final standard of 0.8 g/mi. Trucks under 6,000 lb would be required to control HC emissions to 0.41 g/mi, while heavier Class 2B trucks weighing up to 8,500 lb would be required to control emissions to 0.53 g/mi.

The 0.41 g/mi standard would bring the lightest trucks to a compliance level identical to that for passenger cars. These trucks have engine sizes similar to those of automobiles, yet avoid equally stringent control through a technicality. For example, minivans, which are currently categorized as trucks, would fall under the new automobile-equivalent standard. Heavier trucks (to 8,500 lb), which are more representative of commercial types of service vehicles, would have to meet slightly less stringent standards.

Catalytic converters are required on light trucks to meet CO and HC exhaust limitations that have already been promulgated. Since catalysts on automobiles are now capable of providing HC controls at a certification level of 0.41 g/mi and below, compliance with the requirement on trucks should be relatively easy with little, if any, additional research and development costs. Potential reduction of HC exhaust emissions in the year 2000 is estimated to be 400,000 tons.

3.5.3 Sulfur Control Limitations

The maximum sulfur content of diesel fuel allowed by H.R. 4567 would be 0.05% by weight. This regulation would take effect in 1989 and would reduce emissions from diesel-burning engines by about 75%. By the year 2000, SO_2 emissions from the transportation sector would be reduced by approximately 350 tons/yr. Refining costs for reducing the sulfur from crude oil feed stocks, however, would increase by about 1.2 cents per gallon. In addition to reducing SO_2 emissions, this regulation would lead to lower engine maintenance costs and an extended engine life. These cost savings are conservatively estimated to be four times the incremental desulfurization refining costs of 1.2 cents per gallon.

3.5.4 Hydrocarbon Vapor Controls

H.R. 4567 requires that either on-board HC control technologies be placed on automobiles built for the 1989 model year and later or gasoline vapor recovery nozzles and support equipment be installed at all service stations.

EPA has estimated a per-vehicle cost increase of $2 to develop and install the on-board HC control technology. Vehicle manufacturers have estimated that this cost may actually be closer to $20 per vehicle. Despite this discrepancy, there is increasing agreement that this option is superior on a cost-effectiveness basis to requiring vapor recovery at all service stations.

4 ELECTRICITY RATE INCREASES

It is anticipated that the Sikorski bill would increase the cost of producing electricity by about $2.2 x 10^9/yr when full compliance is achieved. Costs of this magnitude could not be absorbed by the electric utilities without increasing electricity rates charged to customers. Section 1 described how electricity rate increases were to be treated under the bill, and indicated that a subsidy was authorized to prevent residential electricity rates rising above 10%, subject to several stipulations. In assessing the potential impacts of the Sikorski bill, it is important to gain an appreciation of the possible increases in electricity rates that may be charged to industrial, residential, and commercial customers.

This question can be approached from two distinctly different points of view. Under a bill such as H.R. 4567, a public utility commission may choose to either increase rates equally among users (residential, commercial, and industrial), or to minimize utility costs by increasing only residential rates, thereby maximizing the amount of money collected from the Acid Deposition Fund. The latter strategy would only be plausible in instances where total pollution control costs would otherwise increase residential rates by more than 10%.

It is unlikely that nonresidential users would experience a disproportionately higher rate increase than residential users. In the past, nonresidential users in many cases have subsidized the cost of electricity supplied to residential users. A recent trend in the utility industry, however, has been to increase residential rates faster than nonresidential rates to obtain economic parity among users and to retain industrial loads. Utilities are reluctant to dramatically increase nonresidential rates since, as seen in the recent past, nonresidential users may become cogenerators of electricity, switch to an alternative energy source, or leave the service territory (swing industries).

States that are projected to experience electricity rate increases greater than 1% are shown in Table 4.1 for two alternative assumptions about control cost financing: (1) costs are financed equally by all users, and (2) costs are financed by residential users only. It should be noted that the rate increases shown in Table 4.1 are based on cost estimates for achieving an annual average SO_2 emission rate limit of 1.2 lb/10^6 Btu and the cost of reducing the state-level NO_x annual emission rate to 0.6 lb/10^6 Btu. These are the emission rate limits specified in the amended (or revised) legislation.

The revised version of the bill will tend to hold down maximum electricity rate increases as compared to the original bill. One major reason for this is that the revised legislation requires approximately 10% less emission reductions than the original bill. Cost savings, however, are substantially greater than 10% since utilities base their decision making on a marginal cost basis. The revised bill also mandates that pollution control costs be evenly distributed in terms of geographic area within a state and that electricity rates be computed on a levelized basis. This is counter to normal utility practices, which have historically used front-end loading to finance their revenue requirements.

TABLE 4.1 Potential State-Level Electricity Rate Increases of 1.0% or Greater Associated with H.R. 4567[a] (least-cost control strategy)

	Control Costs Financed by All Users		Control Costs Financed by Residential Users Only	
State	Front-End-Loaded Financing First-Year Increase (%)	Average Increase (%)	Front-End-Loaded Financing First-Year Increase (%)	Average[b] Increase (%)
Georgia	1.6	1.2	4.6	3.5
Illinois	6.5	3.5	19.3	10.6
Indiana	9.3	6.1	32.0	22.3
Kentucky	2.8	1.8	10.6	7.3
Maryland	2.8	1.5	8.4	4.9
Michigan	1.7	1.1	6.2	4.0
Missouri	9.1	6.6	23.1	17.5
New Hampshire	4.3	2.1	12.5	6.2
Ohio	4.3	3.4	13.2	11.0
Pennsylvania	4.6	2.8	15.9	10.3
S. Carolina	1.4	1.0	4.3	3.1
Tennessee	2.2	1.6	7.4	5.4
W. Virginia	4.3	3.3	14.9	12.3

[a]States with estimated rate increases less than 1% are not shown here. Costs here are due to SO_2 and NO_x controls; the authorized subsidy would apply to only SO_2 costs.

[b]The Acid Deposition Fund would subsidize states such that residential electricity rates would not be increased above 10%, given certain conditions are met. These figures reflect rate increases in the absence of the fund.

Table 4.1 shows that no state would experience rate increases in excess of 10% if control costs were financed by all users. The largest average rate increases would be in Missouri (6.6%) and Indiana (6.1%). First-year rate increase estimates for a front-end loaded financing strategy could be as high as 9% for these two states. These results suggest that the control fund would be unnecessary. Under the improbable circumstance that all costs would be financed by residential users, average rate increases would exceed 10% in six states, with Indiana and Missouri again experiencing the greatest increases.

Due to the political forces involved in determining how emission reductions will be achieved, state officials may choose to opt for a strategy that would be more costly for the utilities but would protect a vital industry within the state. For example, states that have a high-sulfur coal-mining industry may require SO_2 emission reductions to be achieved through the use of scrubbers. This requirement would help protect the coal-mining industry, but would substantially increase emission control costs. There are six states -- Illinois, Indiana, Kentucky, Pennsylvania, Ohio, and West Virginia -- that appear most likely to adopt this type of strategy. Table 4.2 shows those states that have extensive high-sulfur coal-mining operations and also consume a large fraction of coal produced within their own state. Table 4.3 shows what electricity rates may be expected if the forced scrubbing option were to be selected by each state in this group.

Average rate increases would still not exceed 10% in these six states if forced scrubbing strategies were chosen. However, first-year rate increases in Indiana and Ohio might exceed 10%, as might those increases that would result if residential customers financed all control costs.

Base-case electricity rate increases are based on the NEPP-V reference case. In this reference scenario, electricity demand in the United States is projected to increase by 49% from 1984 to the year 2000 and by 83% from 1984 to the year 2010. If electricity growth were not as high, electricity rates and their associated impacts would be larger. With lower demand growth rates, fewer NSPS units would be built. The NSPS units have much lower SO_2 and NO_x emission rates than SIP units, and therefore decrease the state-level average emission rates of these pollutants. Electricity rates would be higher since under a low-growth scenario there would be less electricity sales over which to spread the cost of the legislation.

The Sikorski bill authorizes the establishment of an acid deposition control fund to subsidize residential rate increases greater than 10%. The fee would be effective from January 31, 1988, through January 31, 1996, and would not be permitted to exceed 0.5 mill/kWh. Although it appears that rate increases may not be sufficient to trigger the control fund requirements, we have estimated the revenues that would be generated if all states were taxed at the same rate.

Table 4.4 calculates revenues that would be generated at a fee of 0.5 mill/kWh. Annual electricity generation from fossil-fuel combustion in the early 1990s is projected to be a little over 2×10^{12} kWh. Thus, annual revenues collected would be about \$$1 \times 10^9$. We calculate that total revenues over the 8-year period of the fund would be approximately \$$8.7 \times 10^9$ at a fee of 0.5 mill/kWh. Also shown in Table 4.4 are revenues for a fee of 0.2 mill/kWh and for a fee levied on *all* electricity generated, for comparison.

TABLE 4.2 States That Might Mandate Scrubbing

State	Fraction of State Coal Demand in 1980 Produced in the Same State	Fraction of State Coal Demand in 1980 Produced in One of the Six Listed States
Illinois	.54	.59
Indiana	.55	.85
Ohio	.53	.95
Pennsylvania	.85	.99
W. Virginia	.90	1.00
Kentucky	.92	.99

TABLE 4.3 Potential Electricity Rate Increases Associated with H.R. 4567 for the Six States That Have a High-Sulfur Coal-Mining Industry (forced scrubbing strategy)

	Control Cost Rates Financed by All Users		Control Cost Rates Financed by Residential Users Only	
State	First Year Increase (%)	Average Increase (%)	First Year Increase (%)	Average[a] Increase (%)
Illinois	8.6	4.2	25.5	8.0
Indiana	10.6	6.4	36.6	21.9
Kentucky	4.1	2.2	15.8	7.8
Ohio	12.1	7.2	37.2	23.1
Pennsylvania	5.8	3.5	20.2	12.7
W. Virginia	6.8	4.3	23.8	15.1

[a]The Acid Deposition Fund would authorize subsidies to states such that residential electricity rates would not increase above 10%, given certain conditions are met. These figures reflect rate increases in the absence of the fund.

TABLE 4.4 Revenues Generated by the H.R. 4567 Tax Fund

	Electricity Generation (10^9 kWh)		Electricity Consumption (10^9 kWh)[b]	Revenues at 0.5 mill/kWh ($\$10^6$/yr)[c]		Revenues at 0.2 mill/kWh ($\$10^6$/yr)[c]	
Year[a]	Fossil Only	All Fuels[d]	All Fuels[d]	Fossil Only	All Fuels[d]	Fossil Only	All Fuels[d]
1989	2,013	2,889	2,608	1,006	1,445	403	578
1990	2,041	2,962	2,674	1,021	1,481	408	593
1991	2,090	3,044	2,747	1,045	1,522	418	609
1992	2,140	3,125	2,821	1,070	1,563	428	625
1993	2,189	3,206	2,894	1,094	1,603	438	641
1994	2,238	3,288	2,968	1,119	1,644	448	658
1995	2,287	3,369	3,041	1,144	1,684	458	674
1996	2,343	3,450	3,114	1,172	1,725	469	690
Cumulative Totals[e]				8,671	12,667	3,468	5,067

[a]Fund operational during the period 1989-1996.

[b]The bill specifies electricity generation from fossil fuel as the basis for revenue collection. Note that electricity consumption is less than electricity generation due to transmission losses.

[c]Revenues are in nominal dollars. To compare with the cost estimates in Table 3.5, each value would have to be deflated from the appropriate future year to 1985 dollars.

[d]Includes not only nuclear and hydroelectric generation, but small amounts of geothermal and renewables.

[e]Revenues would only be collected "if needed." Analysis suggests that electricity rate increases may not be high enough to trigger subsidies.

5 EFFECTS ON MANUFACTURING INDUSTRIES

Within the industrial sector, industries differ in how they use electricity; some industries are large users of electricity but the costs of electricity are small compared to total production costs, whereas other industries are "electricity-intensive." Industries that are electricity-intensive consume a large quantity of electricity per unit of production activity. As a result, these industries are likely to be the most sensitive to changes in the price of electricity.

Generally, the industries classified as electricity-intensive have relied largely (often exclusively) on electricity. Currently, many of these industries -- primary metals, aluminum and zinc, for example -- are suffering from severe international competition. Since the aluminum and zinc industries are highly electricity-intensive industries, their international competitiveness is influenced by electricity rates. In these cases, any change in electricity rates is likely to affect their competitive position in the market place. The analysis presented herein is confined to the domestic impacts of rate changes induced by H.R. 4567 on electricity-intensive industries. Section 5.4 examines the aluminum industry in more detail -- particularly in Kentucky and Maryland -- in order to determine likely effects of industrial electricity rate increases induced by H.R. 4567.

5.1 ELECTRICITY-INTENSIVE INDUSTRIES

This analysis relies on a classification of electricity-intensive industries developed by the Office of Technology Assessment (OTA),[31] in which 17 industries were considered to be electricity-intensive (see Table 5.1). OTA used a twofold definition to identify these industries: an industry is electricity-intensive when the cost of electricity is (1) 4% or more of the total value of shipments or (2) 10% or more of the total "value added." The 17 industries complying with this definition are largely concentrated in the areas of primary metals; chemicals, particularly industrial inorganic chemicals; and stone, clay and glass products. According to OTA, the identified industries account for a disproportionate share of U.S. industrial electricity use; these industries account for approximately 2% of total value of shipments and 2% of total value added by U.S. manufacturing industries, but purchase approximately 25% of the electricity sold to industry, and account for 16% of utility revenues from industrial electricity sales.[31]

Five industry groups identified in Table 5.1 are more electricity-intensive than the others: electrometallurgical products, primary zinc, primary aluminum, alkalies and chlorine, and industrial gases. For each of these industries the cost of purchased electricity in 1980 equaled about 40% or more of their total value added, and 10-25% of their total value of shipments (see Appendix D, Table D.1). Because electricity costs are a large share of the total product value, these industries are likely to be the most sensitive to any increase in the cost of electric power. For this reason, these 17 industries will be used to illustrate the potential effects of electricity rate changes induced by H.R. 4567. It should be noted, however, that industries other than the 17 listed in Table 5.1 would also be affected by the passage of H.R. 4567.

TABLE 5.1 Top Seventeen Electricity-Intensive Industries

Industry	SIC Code
Cotton seed oil mills	2074
Manufactured ice	2097
Particle board	2492
Alkalies and chlorine	2812
Industrial gases	2813
Other industrial inorganic chemicals	2819
Carbon black	2895
Reclaimed rubber	3031
Cement, hydraulic	3241
Lime	3274
Mineral wool	3296
Electrometallurgical products	3313
Malleable iron foundries	3322
Primary zinc	3333
Primary aluminum	3334
Other primary nonferrous metals	3339
Carbon and graphite products	3624

Source: Ref. 31.

The financial position of each company and market factors are important elements not incorporated in this analysis. For example, several of these electricity-intensive industries are highly susceptible to foreign competition, since electricity costs in some foreign countries are significantly below the lowest rates in the United States. Primary zinc and aluminum are two embattled industries that have been losing a large share of domestic production to foreign producers over the past decade, principally due to differences in electricity costs.

5.2 LOCATION AND IMPORTANCE OF ELECTRICITY-INTENSIVE INDUSTRIES

In Sec. 4, seven states were identified as likely to have electricity rate increases above 4% from implementation of H.R. 4567. These states were Illinois, Indiana, Missouri, New Hampshire, Ohio, Pennsylvania, and West Virginia. This section examines the location and importance of the 17 electricity-intensive industries in these states.

According to the *1982 Census of Manufactures*,[32] the 17 electricity-intensive industries have 2,847 establishments in the United States with more than 150 employees.* Approximately 20% of these electricity-intensive establishments are located in the seven states identified above. Three of the states have a relatively high share of total U.S. establishments in these industries: Illinois (2.7%), Ohio (5.5%), and Pennsylvania (5.3%). Within each of the seven states examined, the distribution of establishments across electricity-intensive industries varies (see App. D, Table D.2). For example, 68% of the electricity-intensive establishments in Illinois were concentrated in just two industries, industrial gases (2813) and other industrial inorganic chemicals (2819). Most other states also have a large share of establishments in these two industry groups. However, when analyzed collectively (i.e., all seven states combined), these two industry groups were not the most highly represented in terms of the proportion of establishments; their share in the seven states was 21.1% and 22.3%, respectively.

Table 5.2 presents the share of electricity-intensive establishments within the seven high-impact states. Ten of the 17 electricity-intensive industries have more than 20% of their establishments in the 7 high-impact states by industry group. As a result, a large number (and share) of establishments in each of these 10 industry groups are located in the states likely to incur the greatest rate increases from realization of H.R. 4567. The degree of impact on these industries is not only a function of the number of establishments, but also a function of the size of these industries (measured by the size of their labor force) and the importance of their output (measured by value added or value of shipment). Therefore, even though these industries are electricity-intensive and have a large number of establishments located in states projected to have a considerable rate increase under H.R. 4567, unless these industries comprise a large share of state industrial output and employment or are a large share of industrial activity (nationally), then negative impact from a rate increase may not be significant regionally or nationally, but could be very significant at a local level.

One indication of the importance of these electricity-intensive industries to the seven states is their employment levels. Total employment in the 17 electricity-intensive industries was 223,000 in 1982. Two states examined have high employment concentrations in these industries: Ohio (9.6%) and Pennsylvania (6.2%). Four other states (Illinois, Indiana, Missouri, and West Virginia) have between 2.3 and 2.9% of total employment in these electricity-intensive industries. (See App. D, Table D.3 for employment data by industry and state). Collectively, these states have 26.3% of total national employment in the 17 industries.

Although state employment in these electricity-intensive industries appears relatively important when compared to total U.S. employment in these industries, it is relatively small when compared to state manufacturing employment. Figure 5.1 shows the electricity-intensive share of manufacturing employment by state. West Virginia has

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*The *1982 Census of Manufactures* only presents statistics for establishments with more than 150 employees. All subsequent industry data presented is subject to this qualification. Consequently, some establishments may be omitted from state totals and thereby underestimate the degree of impact. In addition, disclosure problems in the Census of Manufactures sometimes prevent presentation of complete data for each state and industry.

TABLE 5.2 Share of Electricity-Intensive Establishments in High Impact States[a]

Industry	SIC Code	Share (%)
Cotton seed mills	2074	0
Manufactured ice	2097	0
Particle board	2492	0
Alkalies & chlorine	2812	9.8
Industrial gases	2813	21.1
Other industrial inorganic chemicals	2819	22.3
Carbon black	2895	0
Reclaimed rubber	3031	38.5
Cement, hydraulic	3241	24.5
Lime	3274	27.6
Mineral wool	3296	30.2
Electrometallurgical products	3313	31.7
Malleable iron foundries	3322	24.0
Primary zinc	3333	37.5
Primary aluminum	3334	8.8
Other primary nonferrous metals	3339	13.3
Carbon and graphite	3624	31.9

[a]Only establishments with greater than 150 employees are included.

Source: Computed from Table D.2 (App. D).

the largest share of electricity-intensive employment (5.5% of manufacturing employment), while most of the other states have around 1-2%. This graphic illustrates that employment in electricity-intensive industries is relatively minor when compared to manufacturing employment.

The importance of these electricity-intensive sectors to industrial output and state activity is best related by using either value-of-shipments or value-added data. For our purposes, value of shipments reported in the *1982 Census of Manufactures* is used.* For many industries, disclosure problems prevent presentation of state data. Nevertheless, an appreciation of the importance of these electricity-intensive industries to national and state activity can be derived.

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*A similar analysis could be performed using value-added data. Such an analysis would indicate the same patterns presented herein for value of shipments (see App. D, Table D.5).

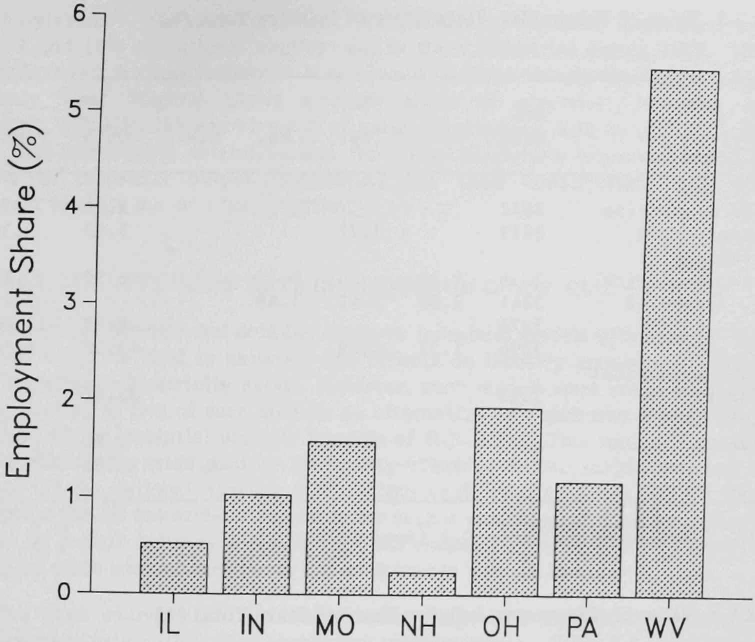

FIGURE 5.1 Electricity-Intensive Industry Share of Manufacturing Employment by State

Table 5.3 relates the state share of value of shipment for each electricity-intensive industry. State shares are only presented where industries exist at the state level and data were not suppressed due to disclosure problems. (See App. D, Table D.4 for a detailed reporting of these data). Because most state shares presented in Table 5.3 are large, either individually or collectively, any change in value of shipments from one of these electricity-intensive industries (due to an electric rate increase) would appear to have a considerable impact on industry output (nationally).

The importance of these electricity-intensive industries to state activity is also a critical aspect of this analysis. Table 5.4 relates electricity-intensive industry shares of total state shipments; shares are only presented for those industries where data were available. In every case the shares are less than 1%, indicating that these electricity-intensive industries do not make a substantial contribution to annual shipments of state manufactured products.

From this discussion of the location and importance of electricity-intensive industries it has been shown that a large share of electricity-intensive establishments are located in the seven states likely to have large prospective rate increases as a result of H.R. 4567. Moreover, these industries are concentrated in three states: Illinois, Ohio,

TABLE 5.3 Value of Shipments: State Share of Industry Total (%)

Industry	SIC Code	Ill.	Ind.	Mo.	N.H.	Ohio	Penn.	W.V.
Alkalies & chlorine	2812					2.94		
Industrial gases	2813		7.77			5.93	5.39	
Other industrial inorganic chemicals	2819	4.23		0.75		6.90	3.72	
Cement, hydraulic	3241	2.00	2.42	3.48			7.46	
Lime	3274					8.39	17.90	
Mineral wool	3296	1.57	6.09			16.20	6.10	
Electrometallurgical products	3313					35.41		
Malleable iron foundries	3322					9.72		
Carbon and graphite	3624	1.67			8.77	16.68		

Source: Tabulated from Table D.4 (App. D).

TABLE 5.4 Value of Shipments: Industry Share of State Total (%)

Industry	SIC Code	Ill.	Ind.	Mo.	N.H.	Ohio	Penn.	W.V.
Alkalies & chlorine	2812					0.04		
Industrial gases	2813		0.25			0.11	0.11	
Other industrial inorganic chemicals	2819	0.45				0.74	0.44	
Cement, hydraulic	3241	0.06	0.14				0.26	
Lime	3274					0.04	0.09	
Mineral wool	3296	0.03	0.22			0.33	0.14	
Electrometallurgical products	3313					0.22		
Malleable iron foundries	3322					0.03		
Carbon and graphite	3624	0.01				0.08	0.16	

Source: Tabulated from Table D.4 (App. D).

and Pennsylvania. State employment in electricity-intensive industries averaged between 2 and 10% of national employment in these industries during 1982. However, when employment in these industries is compared to total manufacturing employment by state, only West Virginia shows a large share of electricity-intensive industry employment. Finally, the examination of value-of-shipment data by state and industry conveys that state-level establishments for these electricity-intensive industries are important to industrial output (nationally) but their contributions are relatively insignificant to state manufacturing activity.

5.3 IMPACT OF ELECTRICITY RATE INCREASES ON INDUSTRIAL ACTIVITY

In a more thorough and detailed analysis, industrial models with appropriate price elasticities would be used to estimate the effects on industry employment and output from an increase in electricity rates. However, such models were not readily available for this exercise. In lieu of such models, an alternative approach was devised to gain an appreciation of the potential industry impacts of H.R. 4567. This approach consisted of examining electricity rates paid by electricity-intensive industries in the seven states, relative to (1) the national average price within each industry group and (2) the state average price for all industries. The basis for such a comparative analysis is electricity price data by 3-digit industry group in the *1980 Annual Survey of Manufactures*[33] (The price data by state and industry group are exhibited in App. D, Table D.6).

The first examination consists of comparing state electricity rates with the national average rate within each respective industry group. Table 5.5 shows the ratios of state to national electricity rates for each electricity-intensive industry group. Values below 1.00 indicate that industries paid less than the national average price in 1980. There are numerous examples where the ratio is less than 1.00; for example, iron and steel foundries (332) have slightly favorable rates in Illinois (0.97 of industry average) and Indiana (0.93). In three of the other four states, the state electricity rates are very close to the industry average. In general, the electricity rates paid by electricity-intensive industries in the seven states are less than, or approximate, the respective industry averages.

It is unlikely that the ratios would be altered substantially. Even if the state rates increased to parity with the industry average, such an adjustment may not be enough of an inducement to cause these industries to relocate or radically adjust production schedules. With parity in electricity rates, other location factors would become prominent for these electricity-intensive industries. It is also important to note that these rates are at the 3-digit level by state; different -- often more favorable -- rates may apply to the specific industries and establishments of concern in local electric power service districts.

A similar examination was conducted using the ratio of industry group electricity rates to the average industrial rate for the state (see App. D, Table D.7). Such a ratio relates how the rate paid by electricity-intensive industries compares to the average rate paid by all manufacturing establishments in the state. This comparison also indicates the industries with the more favorable state industrial electricity rates. Generally, the same state-industry combinations that had low ratios in Table 5.5 also had low ratios when

TABLE 5.5 Ratio of Industry Group Electricity Rates: State to National

Industry	SIC Code	Ratios By State						
		Ill.	Ind.	Mo.	N.H.	Ohio	Penn.	W.V.
Fats & oils	207	0.90	0.92	1.03	--	1.06	--[a]	--
Misc. foods, kindred products	209	1.10	--	0.95	--	0.91	--[a]	--
Misc. wood products	249	--	1.06	1.25	1.43	1.22	--[a]	--
Industrial inorganic chemicals	281	1.21	--[a]	--[a]	--	0.81	1.13	--[a]
Misc. chemical products	289	1.24	--	0.73	--	0.98	1.09	--
Reclaimed rubber	303	--	--	--	--	--	--	--
Cement, hydraulic	324	--	--	--	--	0.83	1.02	--
Concrete, gypsum, plaster prod.	327	1.05	0.82	--[a]	--	1.04	1.03	--[a]
Misc. nonmetallic mineral prod.	329	1.20	1.02	--[a]	1.37	0.89	1.02	--[a]
Blast furnace, basic steel prod.	331	1.05	1.20	--	--	0.88	1.09	--[a]
Iron & steel foundries	332	0.97	0.93	1.01	1.22	1.03	1.05	--[a]
Primary nonferrous metals	333	--	--	--[a]	--	--	--[a]	--
Electrical industrial apparatus	362	--[a]	0.96	1.05	1.77	1.22	0.89	--

[a]Could not be computed due to disclosure problems with electricity rate data.

Source: Computed from Table D.6 (App. C).

state electricity rates were compared to the state industrial average. In those cases where electricity-intensive industries are paying more for electricity than the state industrial average, it can be concluded that other factors besides electricity rates cause industries to locate and produce in particular states. It should be noted that many of these latter industries have an electricity rate competitive with the industry average (nationally), even though their rate is greater than the state average. Consequently, based on this preliminary examination it appears that only a substantial rate increase would cause a redistribution of industrial activity.

Since the general rate increase projected for the seven high-impact states under H.R. 4567 is in the range of 2-6%, electricity-intensive industries are likely to have some negative impacts from such a rate change but it would probably not induce them to relocate or cause a redistribution of industrial activity. However, there may be particular establishments in the high-impact states examined that would be severely affected. For example, the primary zinc and aluminum sectors have severe competition from imports and a small increase in costs may have more serious repercussions.

5.4 POTENTIAL IMPACTS ON THE ALUMINUM INDUSTRY IN KENTUCKY AND MARYLAND

Aluminum is the largest nonferrous metal industry in the United States. It is also one of the top five industrial energy users in the nation. The locations of primary aluminum plants in the United States are shown in Fig. 5.2.[34] Capacity is concentrated in five main electric service areas: the Bonneville Power Administration (BPA) and Tennessee Valley Authority (TVA) service areas, the Ohio River Valley Region, the Gulf

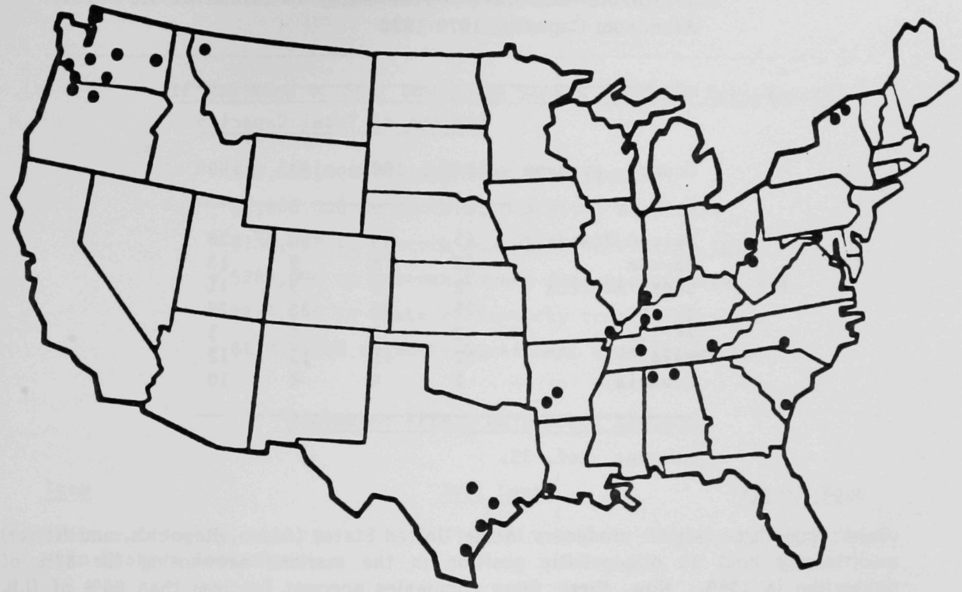

FIGURE 5.2 Location of U.S. Primary Aluminum Industry (Source: Ref. 34)

Coast, and New York State.[35] Nearly one-half of the U.S. capacity is located in the BPA and TVA service areas due to their historically inexpensive electric power.

There are two primary aluminum plants in Kentucky and one in Maryland. The employment in primary aluminum for each of these two states exceeds 1,000 workers.[28] Hence, both states will be affected if their primary aluminum industry is curtailed. This section will briefly summarize the status of the primary aluminum industry in the United States, and then discuss the situation for Kentucky and Maryland.

As shown in Table 5.6, the U.S. share of free-world aluminum capacity has declined from 45% in 1970 to an estimated 26% in 1990. Because aluminum production is very energy-intensive, the differential between power rates charged by U.S. electric companies and power rates charged in other countries is the most influential factor behind this shift. Power rates to the U.S. primary aluminum industry are among the highest in the world. The average price of electricity paid by U.S. aluminum companies was 23 mills/kWh in 1983, compared to an average 17 mills/kWh in other aluminum-producing countries.

The structure of the U.S. industry has changed as well. Eleven companies produce primary aluminum in the United States. However, where the industry could be called strongly oligopolistic in 1960, it has become increasingly competitive in recent

TABLE 5.6 U.S. Share of Free-World Aluminum Capacity, 1970-1990

	Percent of Total Capacity			
Country or Area	1970	1980	1985	1990
United States	45	36	30	26
Canada	12	8	9	13
South America	2	6	9	11
Europe	25	27	26	23
Africa	2	3	4	5
Asia	12	15	13	12
Oceania	2	4	8	10

Source: Ref. 35.

years. The three largest producers in the United States (Alcoa, Reynolds, and Kaiser) traditionally held an oligopolistic position in the market, accounting for 87% of production in 1960. Now, these three companies account for less than 60% of U.S. output.

Kentucky faces a serious situation regarding aluminum production and electricity rates in the western part of the state. Two aluminum companies, National-Southwire Aluminum (NSA) and ARCO, consume 75% of the power generated by Big Rivers Electric Corporation (sold through distributor cooperatives). In 1980, Big Rivers began construction on D.B. Wilson, a 400-MW coal plant, requiring them to borrow $\$1.1 \times 10^9$ in loans guaranteed by the Rural Electrification Administration. Four years later, the plant was finished, but the entire load was considered excess capacity.

Big Rivers requested a rate increase in order to bring D.B. Wilson on line, but was refused by the Kentucky Public Service Commission. In private negotiations with the two aluminum companies, Big Rivers reached agreement on a \$7.00/kW demand charge applied for 10 yr, but later increased the charge to \$7.48. NSA would not agree to pay the additional 48¢, stating that the change would increase its operating costs by at least $\$2 \times 10^6$. Therefore, Big Rivers is unable to earn a return on the new plant and consequently may default on the REA guaranteed loans.

NSA claims that the increase requested by Big Rivers may cause it to shut down its Hamesville, Kentucky, plant. If that were to occur, the impacts to the economy would be serious in that area. NSA accounts for 900 jobs, amounting to payroll and benefits of approximately $\$28 \times 10^6$. According to NSA, another $\$2.6 \times 10^6$ is spent by these employees on health care alone. The estimate of tax revenue losses to state and local government is approximated at $\$1.6 \times 10^6$. Full impacts of aluminum industry curtailment in Kentucky, as disclosed by NSA, are shown in Table 5.7.

TABLE 5.7 Estimated Job Losses Associated with NSA Shut Down

If NSA Were to Shut Down, the Losses Would Be Substantial

- 900 Jobs
- $28,000,000 Payroll Plus Benefits
- $2,600,000 to Doctors, Dentists, Hospitals
- $130,000 to Hancock Schools from Utility Tax
- $282,000 to Hancock County from Occupational Tax
- $216,000 to State of Kentucky from utility Tax
- $1,000,000 to State Government from Income Tax

Estimated Effect on Western Kentucky

Item	Jobs Lost	Payroll Loss
Smelter Industry in Western Kentucky	1,800	$55,000,000
Smelter Related	1,278	$19,000,000
[a]Coal (Miners)	663	$21,000,000
[a]Associated Jobs to Coal Jobs	470	$ 7,000,000
Total	4,211	$102,000,000

[a]This relates the smelter industry's power demand to mining jobs.

[b]The smelter-related jobs and associated jobs to coal jobs lost are calculated by using figures from a report published by Associated Industries of Kentucky demonstrating 100 new jobs. If it has the same value for 100 jobs lost, the 2,463 jobs related to the smelter and mining industry would equate to 1,748 related jobs lost. The above figures do not show what would be lost in tax revenues and unemployment costs.

Source: NSA as cited in Ref. 35.

The average electricity rate increase for Kentucky was estimated to range from 1.8 to 2.2%. Any additional rate increases would exacerbate the present situation. If the Kentucky aluminum industry continues to operate, the current dilemma facing the industry will be compounded by the passage of the proposed acid rain control legislation.

Although the aluminum industry is a concern in Maryland, the situation is not nearly as serious. There is one primary aluminum plant in Frederick, Maryland (East Alco). East Alco is served by Potomac Edison. Recently, Potomac Edison and the Maryland Public Utility Commission have been careful in their allocation of increases to the aluminum operation. In addition, the Commission recently approved an experimental development rate for East Alco. This is a special electricity rate discount for new capacity brought into the area. According to the ANL projections, Maryland may face an electricity increase of 1.5%. Such increases should not affect the industry significantly.

6 COAL MINING EMPLOYMENT IMPACTS

In addition to effects on electricity-intensive manufacturing industries, H.R. 4567 may have significant impacts on regional coal-mining production and employment. In order to provide an appreciation of the shifts that may occur in coal mining production and employment, regional projections of future coal production, mining productivity levels, and estimates of coal demand shifts attributed to H.R. 4567 were estimated.

Regional coal production estimates for 1997 were derived through a multistep process incorporating several sources of information. First, regional production shares were derived from the Energy Information Administration (EIA) regional coal production projections.[36] These regional production shares were then applied to national-level NEPP-V projections of utility coal demand in order to estimate regional reference case production levels in 1997. Coal projection estimates were based on the assumption that there would be no changes in present air-quality regulations. Shifts in regional coal production attributed to H.R. 4567 were then estimated by applying percent changes in regional coal production to the reference-case regional coal production. Percent changes in regional coal production were determined from AIRCOST model runs.

Coal-mining employment levels were estimated for the reference case and for the two emission reduction strategies described earlier (least-cost and forced scrubbing in six states). Estimates were based on ANL projections of future coal production and productivity levels, which were derived from CEUM model outputs as reported by ICF.[37] ICF documents provided estimates of coal production and employment for 1990 and 1995. Assuming the five-year productivity growth rate for each region will continue through 1997, ANL derived and used the productivities implicit in the ICF figures. By dividing production by employment and extrapolating, productivity was forecast two additional years. These productivity estimates were used to calculate employment levels associated with coal production under the reference case and for each of the emission reduction strategies.

When emission reductions are imposed on states through an acid-rain control program, tensions are induced in existing coal markets. Those states that currently burn high-sulfur coal are faced with the prospects of either installing FGD systems and continuing to burn high-sulfur coal (the more-expensive option), or switching to low-sulfur coal (which is the cheaper option, but which can adversely impact the local coal industry). The major markets between which these tensions are felt are Northern Appalachia (high-sulfur coal) and Central Appalachia (low-sulfur coal), and Midwest (high-sulfur coal) and West (low-sulfur coal). Figure 6.1 illustrates this phenomenon.

Estimates of future coal production and mining employment for the least-cost control strategy and for the forced scrubbing strategy are shown in Tables 6.1 and 6.2, respectively. Under the least-cost control strategy, high-sulfur coal regions (Northern Appalachia and the Midwest) have the greatest negative impacts, while regions with lower-sulfur coals (Central Appalachia and the Great Plains) are projected to significantly increase coal production. When the utilities located in the eight high-sulfur coal producing states are forced to scrub, shifts in coal production and mining employment are much less than shifts under the least-cost control strategy.

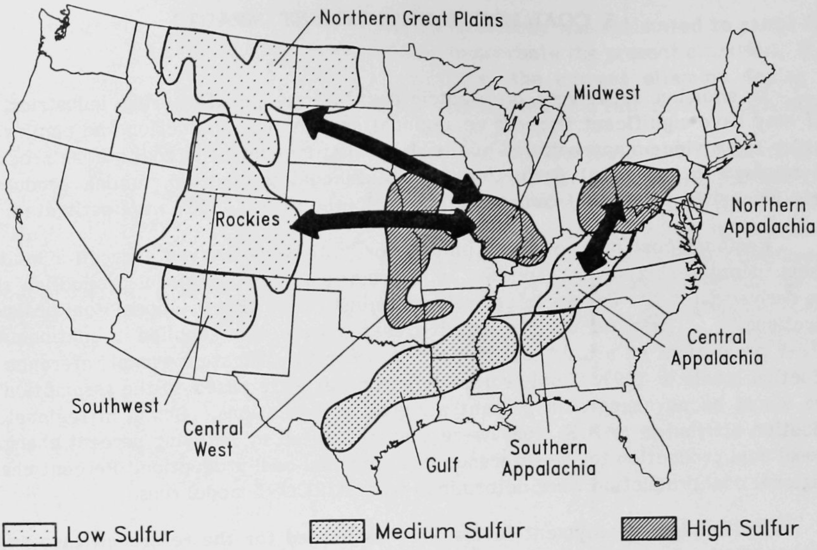

FIGURE 6.1 Coal-Producing Regions of the United States, Showing Market Tensions Induced by Acid-Rain Control Programs

Figure 6.2 portrays coal production changes in the Midwest and Northern Great Plains under several scenarios. Since coal production is expected to grow by about 3%/yr under the NEPP-V reference case scenario, an increase in midwestern coal production of about 30% is anticipated between 1980 and 1997 in the absence of any acid-rain control legislation.

If H.R. 4567 were to be implemented and compliance achieved on a least-cost basis, significant switching away from local high-sulfur coals would occur, such that 1997 midwestern production levels would be about 5% lower than in 1980. A strategy of high-sulfur coal protection would translate this production decline into an increase of 11% relative to 1980. Figure 6.2 shows corresponding effects for the Northern Great Plains. An increase in coal production is expected in all scenarios for 1997, reflecting an anticipated heavy demand for low-sulfur coal in the West. The bill has a positive effect on production and the protection scenario has a negative effect. Figure 6.3 shows a similar outlook for coal production in the Northern and Central Appalachian regions.

Employment changes calculated in this study represent primary impacts only. These are the direct job losses due to coal production declines. The secondary and repercussionary impacts throughout the economy have not been accounted for in this analysis. For example, if coal-mining employment within a region declines by a certain level, then there will be less spending in the local economy as a result. This causes a ripple effect that can be translated into income and employment losses throughout the local economy. Income, output, and employment multipliers can be derived to estimate

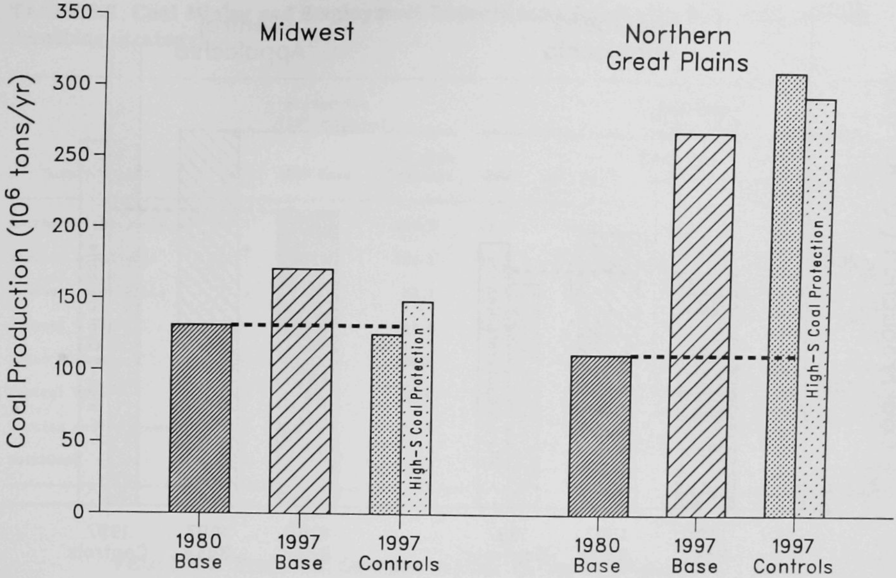

FIGURE 6.2 Changes in Coal Production in the Midwest and West Under the Sikorski Bill, H.R. 4567

the secondary impacts that occur across all sectors resulting from such an economic event; however, for this analysis, only the direct effects are reported. As a result, the total impacts of each scenario would certainly be greater than what is shown in Tables 6.1 and 6.2.

Coal-mining employment declines should not be viewed as "number of layoffs" because national attrition will reduce the present work force. In some regions where coal production is growing in the base case from present values, reduced employment estimates can be viewed as a lower rate of growth.

Table 6.3 shows estimated changes in coal-industry employment levels between 1980 and 1997 in the four major regions. It can be seen that H.R. 4567 results in only a small decline in total employment levels in the four regions, but significantly shifts the regional distribution. The coal protection scenario restores the balance of regional distribution, but significantly reduces total employment levels.

Regional trends tend to mask or overshadow local trends. As regards coal industry employment, it is possible that significant adverse effects could be experienced in individual subregions. For example, Southern Illinois currently produces about 46% of midwestern high-sulfur coal. Without H.R. 4567, this subregion could look forward to an additional 5,000 jobs by 1997; under a least-cost version of H.R. 4567, employment levels in 1997 would decline by about 1,000 jobs relative to 1980 levels. The potential impact

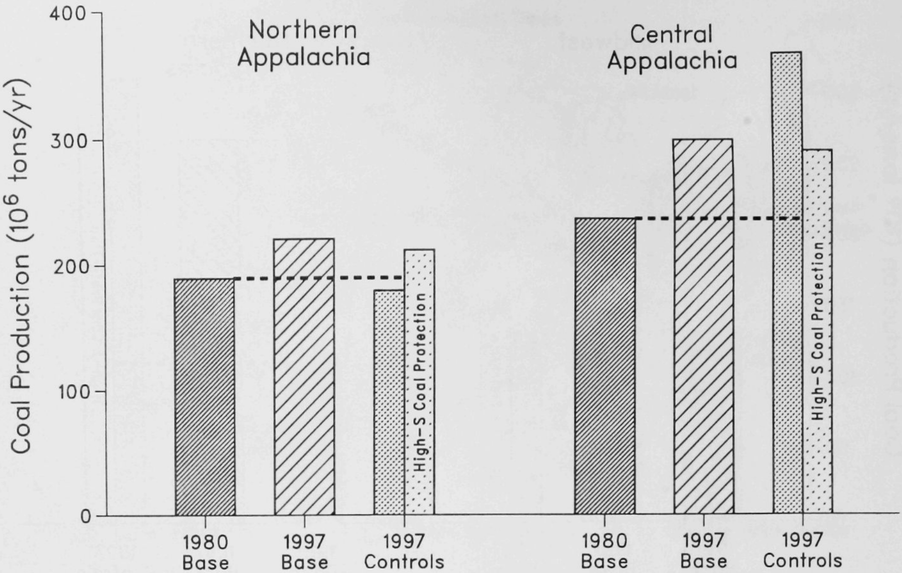

FIGURE 6.3 Changes in Coal Production in Northern and Central Appalachia Under the Sikorski Bill, H.R. 4567

TABLE 6.1 Coal Mining and Employment Impacts Associated with H.R. 4567 (Least-Cost Control Strategy)

	Production (10^6 tons/yr)			Employment (10^3 jobs)				
Supply Region	1980	1997 Base	1997 with Controls	1980	1997 Base	1997 with Controls	Change From Base	Change From 1980
Northern Appalachia	187.3	222.1	178.5	69.8	79.1	63.6	-15.5	-6.2
Central Appalachia	227.9	302.1	361.9	90.6	110.3	132.2	21.9	+41.6
Southern Appalachia	27.3	37.8	48.1	11.8	18.5	23.5	5.0	+11.7
Midwest	133.9	169.4	126.9	35.0	47.6	35.6	-12.0	+0.6
Great Plains	116.4	271.1	313.9	4.9	10.9	12.6	1.7	+7.7
Central West	42.9	101.2	99.5	4.7	12.3	12.1	-0.2	+7.4
Rockies and Southwest	88.2	112.6	111.9	12.7	18.2	18.1	-0.1	+5.4
Northwest	5.8	5.3	5.3	0.6	0.4	0.4	0.0	-0.2

TABLE 6.2 Coal Mining and Employment Impacts Associated with H.R. 4567 (Forced Scrubbing Strategy)

	Production (10^6 tons/yr)			Employment (10^3 jobs)				
Supply Region	1980	1997 Base	1997 with Controls	1980	1997 Base	1997 with Controls	Change From Base	Change From 1980
Northern Appalachia	187.3	222.1	213.5	69.8	79.1	76.0	-3.1	+6.2
Central Appalachia	227.9	302.1	292.1	90.6	110.3	106.6	-3.7	+10.0
Southern Appalachia	27.3	37.8	48.1	11.8	18.5	23.5	5.0	+11.7
Midwest	133.9	169.4	148.3	35.0	47.6	41.7	-5.9	+6.7
Great Plains	116.4	271.1	296.0	4.9	10.9	11.9	1.0	+7.0
Central West	42.9	101.2	99.0	4.7	12.3	12.0	-0.3	+7.3
Rockies and Southwest	88.2	112.6	0	12.7	18.2	18.2	0	+5.5
Northwest	5.8	5.3	5.3	0.6	0.4	0.4	0	-0.2

TABLE 6.3 Projected Changes in Coal Mining Employment Levels Between 1980 and 1997 in Four Major Production Regions

	Employment Change (10^3 Jobs)		
Coal Supply Region	Base	H.R. 4567	H.R. 4567 With High-S Coal Protection
Northern Appalachia	9.3	-6.2	6.2
Central Appalachia	19.7	41.6	10.0
Midwest	12.6	0.6	6.7
N. Great Plains	6.0	7.7	7.0
Total for Four Regions	47.6	43.7	29.9

on this already-depressed subregion could be severe. In Appalachia, the extent of disruption may depend on the willingness of miners to relocate moderate distances (for example, from high-sulfur coalfields in Northern and Western Kentucky to low-sulfur coalfields in Eastern Kentucky or Tennessee). The traditionally parochial nature of the industry in Appalachia, however, suggests resistance to such upheaval.

The estimates of employment shifts provide a general appreciation of the impacts that may arise as a result of H.R. 4567. Given the methodology employed, these estimates can only represent the general magnitude and direction of the impact and do not represent specific input levels. To generate a more-accurate estimate, many other factors would need to be considered. For example, a thorough consideration of this issue would include the use of a coal production and transportation model to account for supply-side considerations germane to the question of coal industry impacts. AIRCOST is designed from a demand-side perspective to forecast coal production requirements; the supply curve in the model is assumed to be perfectly elastic within each region (i.e., it is assumed that the coal supply in each region is inexhaustible and will remain at a given price regardless of the demand level).

As a result, price changes from congestion effects in coal supply fields are not captured in the allocation of demand to supply regions. This could result in an overestimate of projected coal production in low-sulfur coal regions and an underestimate of coal production in other coal supply regions. Another factor that may alter the outcome is employment. Employment is estimated using productivity figures that vary by region; however, the range in labor productivity from mine to mine is not incorporated in the analysis. It is also important to consider the capacity of existing mines and the transportation network, as well as the ability to expand output to meet the new demands.

Finally, fuel switching on a large scale may be limited by boiler considerations.[31,38] Boilers are designed for specific types of coal. Ash fusion temperature, heating value, and volatile matter content, among other things, are specifically taken into account when designing a boiler. Certain types of low-sulfur subbituminous coals may not burn well in boilers designed for bituminous coals due to excessive boiler slagging and fouling. Particulate-matter control devices (baghouses or electrostatic precipitators) may have to be upgraded if low-sulfur coals are to be burned. In addition, fuel-handling equipment may have to be upgraded because low-sulfur coals are more difficult to pulverize and a greater tonnage of coal is required to generate an equivalent amount of electricity. All of these factors will add to the cost of generating electricity, increase operating problems, and may possibly lead to derating of the unit. Nevertheless, these adversities may still be preferable to those associated with FGD.

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APPENDIX A

FULL TEXT OF AMENDED VERSION OF H.R. 4567, AS REPORTED OUT OF THE HOUSE ENERGY AND COMMERCE SUBCOMMITTEE ON HEALTH AND THE ENVIRONMENT, MAY 20, 1986

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FULL TEXT OF AMENDED VERSION OF H.R. 4567, AS REPORTED OUT OF THE HOUSE ENERGY AND COMMERCE SUBCOMMITTEE ON HEALTH AND THE ENVIRONMENT, MAY 20, 1986

ACID86A

H.R. 4567, As Reported From Subcommittee

SECTION 1. SHORT TITLE AND TABLE OF CONTENTS.

This Act may be cited as the ``Acid Deposition Control Act of 1986''.

Table of Contents

TITLE I--STATIONARY SOURCES

SEC. 101. ACID DEPOSITION CONTROL.

Title I of the Clean Air Act is amended by adding the following new part at the end thereof:

``Part E--Acid Deposition Control

``SEC. 181. EMISSIONS FROM UTILITY BOILERS

``(a) State Plans to Control Emissions.--Not later than 21 months after the enactment of this section, the Governor of each State shall submit to the Administrator a plan establishing emission limitations and compliance schedules for controlling emissions of sulfur dioxide and oxides of nitrogen from fossil fuel fired electric utility steam generating units in the State. The plan shall meet the requirements of subsections (b) and (c).

``(b) PHASE I REQUIREMENTS; 1993 SO_2 EMISSION RATE.--The emission limitations and compliance schedules contained in the plan under this section shall be adequate to ensure that, by January 1, 1993, and thereafter, Statewide emissions of sulfur dioxide (per million Btu of heat input) from the total of all fossil fuel fired electric utility steam generating units in the State shall not exceed an average annual rate of 2.0 pounds per million Btu of heat input.

``(c) PHASE II REQUIREMENTS.--The emission limitations and compliance schedules contained in the plan under this section shall be adequate to ensure that, by January 1, 1997, and thereafter, Statewide emissions from the total of all fossil fuel fired electric utility steam generating units in the State shall not exceed the average annual rate provided in table 1.

TABLE 1

lutant	Average Annual Rate*
fur dioxide...........................	1.2
des of nitrogen.......................	0.6

tes are expressed in pounds per million Btu of heat input.

EC. 182. EMISSIONS FROM INDUSTRIAL BOILERS

``(a) STATE PLANS TO CONTROL EMISSIONS.--Not later than

June 1, 1994, the Governor of each State shall submit to the Administrator a plan establishing emission limitations and compliance schedules for emissions of sulfur dioxide and oxides of nitrogen from from fossil fuel fired steam generating units in the State other than fossil fuel fired electric utility steam generating units. Such State plan may include any emissions limitations and compliance schedules, applicable to any such units within the State, which the State deems appropriate and which are adequate to ensure compliance with subsections (b) and (c).

``(b) 1997 STATEWIDE AVERAGE SO_2 EMISSION RATE.--The emission limitations and compliance schedules contained in the plan under this section shall be adequate to ensure that, by January 1, 1997, and thereafter, Statewide emissions of sulfur dioxide (per million Btu of heat input) from the total of all fossil fuel fired steam generating units in the State (other than fossil fuel fired electric utility steam generating units) shall not exceed an average annual rate of 1.2 pounds per million Btu of heat input.

``(c) 1997 STATEWIDE AVERAGE NO_x EMISSION RATE.--The emission limitations and compliance schedules contained in the plan under this section shall be adequate to ensure that, by January 1, 1997, and thereafter, Statewide emissions of oxides of nitrogen (per million Btu of heat input) from the total of all fossil fuel fired steam generating units in the

State (other than fossil fuel fired electric utility steam generating units) shall not exceed an average annual rate of 0.6 pounds per million Btu of heat input.

``SEC. 183. INDUSTRIAL PROCESS EMISSIONS.

``(a) INVENTORIES.--The Administrator shall conduct and periodically update a comprehensive annual inventory of emissions of sulfur dioxide and oxides of nitrogen from stationary sources of such air pollutants, including fossil fuel fired electric utility steam generating units, other fossil fuel fired steam generating units, and stationary sources of industrial process emissions.

``(b) IDENTIFICATION OF EMISSION REDUCTIONS FROM INDUSTRIAL PROCESSES.--The Administrator shall identify the total Statewide potential reductions in emissions of sulfur dioxide and oxides of nitrogen which are economically and technically achievable by December 31, 1996 by stationary sources of industrial process emissions in each State. By December 31, 1990, the Administrator shall transmit to each State a statement containing a calculation of the total reductions identified for that State under this subsection, together with an explanation of such calculation.

``(c) EMISSIONS LIMITATIONS.--Not later than June 1, 1994, the Governor of each State shall submit to the Administrator a plan establishing emission limitations and compliance schedules for emissions of sulfur dioxide and

oxides of nitrogen from stationary sources of industrial process emissions. Such State plan may include any emissions limitations and compliance schedules, applicable to any sources of industrial process emissions within the State, which the State deems appropriate and which are adequate to ensure that, by January 1, 1997, the aggregate annual reductions in emissions of sulfur dioxide and oxides of nitrogen from the total of such sources located in the State will be at least equal to the total Statewide potential emission reductions for each of such air pollutants identified by the Administrator under subsection (b).

``SEC. 184. GENERAL PROVISIONS APPLICABLE TO STATE PLANS.

``(a) GUIDELINES.--Not later than 9 months after the enactment of this part the Administrator shall promulgate guidelines for State plans under this part.

``(b) CHOICE OF COMPLIANCE MEASURES UNDER STATE PLANS.--State plans under this part may provide for compliance with the requirements of this part through any emission limitations and other requirements which the State deems appropriate.

``(c) DISPROPORTIONATE EFFECTS AMONG UTILITIES.--The State shall make reasonable efforts to ensure that the emission reductions required for fossil fuel fired electric utility steam generating units under the State plan do not have an unnecessarily disproportionate economic effect on electric utility ratepayers in any region of the State or in any utility service area.

``(d) STUDY AND REPORT TO CONGRESS.--The Administrator shall conduct a study to determine the reduction in acid deposition achieved pursuant to phase I requirements under section 181(b). The study shall also examine the feasibility of meeting the phase II requirements specified in section 181(c). A report containing the results of the study shall be submitted to Congress on or before June 30, 1993.

``(e) CONGRESSIONAL REVIEW OF REQUIREMENTS.--The phase II requirements of section 181(c) and the requirements of section 182 and 183 shall not take effect if, after the receipt of the study under subsection (c), but before January 1, 1994, the Congress enacts legislation providing that such requirements shall not take effect.

``(f) APPROVAL.--

``(1) IN GENERAL.--Within 9 months after the submission of a State plan under this part, the Administrator shall approve the plan if he determines that the plan contains provisions, including compliance schedules with enforceable increments of progress, adequate to ensure that the requirements of this part will be achieved within the applicable time period specified in section 181, 182, or 183, as the case may be.

``(2) CONDITIONAL APPROVALS DISALLOWED.--The Administrator may not approve a plan under this part unless he finds that, under provisions of the plan without any amendment, condition, or other contingency, each emission rate specified in section 181, or 182 or each aggregate reduction level specified in section 183 (as the case may be) will be attained by the date required under those sections.

``(g) DISAPPROVAL.--

``(1) ELECTRIC UTILITY BOILERS--If a State plan is submitted under subsection 181 on or before the required date and the Administrator disapproves such plan, the Administrator shall notify the State of the reasons for such disapproval and the State may resubmit such plan within 6 months from the date on which such notice is provided. If no State plan has been submitted under section 181 within 27 months after the enactment of this section or if no State plan has been approved by the Administrator within 3 years after the enactment of this section, each fossil fuel fired electric utility steam generating unit in the State shall comply with the emissions rate specified in table 2 by the applicable date and thereafter:

TABLE 2

Pollutant	Applicable Date	Emission Rate *
Sulfur dioxide........	January 1, 1993...........	2.0
Sulfur dioxide........	January 1, 1997...........	1.2
Oxides of nitrogen...........	January 1, 1997...........	0.6

Rates are expressed in pounds per million Btu of heat input, averaged on a calendar year basis.

``(2) INDUSTRIAL BOILERS.--If a State plan is submitted under section 182 on or before June 1, 1994 and the Administrator disapproves such plan, the Administrator shall notify the State of the reasons for such disapproval within 6 months after the submission by the State. The State may resubmit such plan within 6 months from the date on which such notice is provided. If no State plan has been submitted under section 182 on or before June 1, 1994 or if no State plan under section 182 has been approved by the Administrator on or before June 1, 1995, each fossil fuel fired steam generating unit in the State shall comply with the emissions rate specified in table 3 by January 1, 1997 and thereafter:

TABLE 3

Pollutant	Emission Rate *
Sulfur dioxide....................................	1.2
Oxides of nitrogen....................................	0.6

Rates are expressed in pounds per million Btu of heat input, averaged on a calendar year basis.

``(3) PLANS FOR PROCESS EMISSIONS--If a State plan is submitted under section 183 on or before June 1, 1994 and the Administrator disapproves such plan, the Administrator shall notify the State of the reasons for such disapproval within 6 months after the submission by the State. The State may resubmit such plan within 6 months from the date on which such notice is provided. If no State plan has been submitted under section 183 on or before June 1, 1994 or if no State plan under section 183 has been approved by the Administrator on or before June 1, 1995, the Administrator shall promulgate a State plan under under section 183 for such State on June 1, 1995.

``(h) ENFORCEMENT.--Each emission limitation in effect under subsection (f) and each requirement of a State plan approved or promulgated by the Administrator under this part shall be treated, for purposes of sections 113, 114, 116, 120, and 304 as a requirement of an applicable implementation plan.

``(i) OTHER APPLICABLE REQUIREMENTS.--Nothing in this part shall be construed to affect or impair the requirements of section 110 (or of any applicable implementation plan) or of any other section of this Act, except that any stationary source which is subject to any such requirements may also be subject to additional requirements under this part.

``(j) AMENDMENT OF PLANS.--Amendments to a plan approved under this part may be submitted to the Administrator from time to time. Such amendments shall be approved or disapproved in the same manner as the original plan.

``SEC. 185. FEES.

``(a) IMPOSITION.--Under regulations promulgated by the Administrator, the Administrator shall impose a fee on the generation and importation of electric energy if any electric utility is eligible for subsidy payments under section 187. Such fee shall be established by the Administrator at such level (and adjusted from time to time) as will ensure that adequate funds are available to make subsidy payments in the amount authorized under section 187. The Administrator shall determine the amount of revenue required before establishing the fee. To the extent that adequate revenues can be raised, the fee shall vary in proportion to the sulfur dioxide emission rate so that a higher fee will be imposed in the case of a higher sulfur dioxide emissions rate. In establishing the fee, the Administrator shall include provisions to protect low income residential electric consumers. The amount of such fee shall not exceed 1/2 mill per kilowatt hour. The fee shall not apply with respect to the generation of electric energy within the United States by

hydroelectric or nuclear power.

``(b) PERIOD OF APPLICATION.--No fee under subsection (a) may take effect before December 31, 1988. No such fee may continue to apply after December 31, 1996. The Administrator may terminate the fee at an earlier date if, under estimates made by the Administrator, sufficient funds have been collected from the fee to fund the subsidy payments authorized to be made under section 187.

``(c) REGULATIONS.--Any regulations promulgated by the Administrator under subsection (a) shall be promulgated by March 1, 1988. The regulations shall set forth the time and manner required for payment of the fee imposed under subsection (a) and the information required to be reported in connection with the payment of such fee.

``(d) ENFORCEMENT.--

``(1) PENALTIES.--Any electric utility (or importer of electric energy) which fails or refuses to pay any amount of a fee imposed under the authority of this section (a) or which fails or refuses to file any report or other document required by the Administrator in connection with the imposition of such fee shall, in addition to liability for any unpaid amount of such fee (and interest on any such unpaid amount), be liable for a civil penalty of $50,000 for each day during which such failure or refusal continues. Any person who makes any false or misleading statement in any such report or other document required by the Administrator in connection with the imposition of such fee shall be liable for a civil penalty of $50,000.

``(2) CIVIL ACTION.--If any electric utility (or importer) which fails or refuses to pay any amount of a fee imposed under subsection (a), fails or refuses to file any report or other document required by the Administrator in connection with the imposition of such fee, or makes any false or misleading statement in any such report or other document required by the Administrator in connection with the imposition of such fee, the Administrator shall bring a civil action against such electric utility (or importer) to collect such fee and any civil penalty applicable under paragraph (1).

``SEC. 186. FUND.

``(a) FUND.--There is established in the Treasury of the United States a trust fund to be known as the `Acid Deposition Control Fund' (hereinafter in this section referred to as the ``Fund''), consisting of such amounts as may be transferred to such Fund as provided in this section.

``(b) TRANSFER OF FEES.--There are hereby credited, out of any money in the Treasury not otherwise appropriated, to the Fund amounts determined by the Secretary of the Treasury (hereinafter in this section referred to as the `Secretary')

to be equivalent to the amounts received in the Treasury from the fees under section 185.

``(c) USE OF FUND.--Amounts in the Fund shall be available only for purposes of making subsidy payments under section 187.

``(d) MANAGEMENT OF FUND.--

``(1) TRANSFERS.--The amounts appropriated by subsection (b) shall be transferred at least monthly from the general fund of the Treasury to the Fund on the basis of estimates made by the Secretary of the amounts referred to in such subsection (b). Proper adjustments shall be made in the amount subsequently transferred to the extent prior estimates were in excess of or less than the amounts required to be transferred.

``(2) REPORTS.--The Secretary shall be the trustee of the Fund, and shall report to the Congress for each fiscal year ending on or after September 30, 1989, on the financial condition and the results of the operations of such Fund during such fiscal year and on its expected condition and operations during the next 5 fiscal years. Such report shall be printed as a House document of the session of the Congress to which the report is made.

``(3) INVESTMENTS.--It shall be the duty of the Secretary to invest such portion of such Fund as is not, in his judgment, required to meet current withdrawals.

Such investments shall be in public debt securities with maturities suitable for the needs of such Fund and bearing interest at rates determined by the Secretary, taking into consideration current market yields on outstanding marketable obligations of the United States of comparable maturities. The income on such investments shall be credited to, and form a part of, such Fund.

``SEC. 187. UTILITY RATE SUBSIDY PROGRAM.

``(a) RATE SUBSIDIES.--The Administrator shall promulgate regulations under this section establishing a program to provide for Federal payments to electric utilities to cover a portion of electric utility rate increases attributable to compliance with the sulfur dioxide emission reduction requirements under section 181.

``(b) PURPOSE OF PAYMENTS TO ASSURE RESIDENTIAL RATEPAYER PROTECTION.--The program established under this section shall provide for payments by the Administrator to electric utilities to protect electric utility residential customers from excessive rate increases due to the imposition of sulfur dioxide emission reduction requirements under section 181.

``(c) AMOUNT OF PAYMENTS.--Payments under this section shall cover the portion of the rates of electric utility residential customers which--

``(1) is attributable to the imposition of requirements for the reduction of sulfur dioxide

emissions pursuant to section 181; and

``(2) exceeds by more than 10 percent of the rates which would have been applicable in the absence of such requirements.

``(d) EQUALIZATION AND LEVELIZATION OF ECONOMIC EFFECTS.--No subsidy payment may be made to a utility in any State under this section unless the Governor of the State has demonstrated to the satisfaction of the Administrator, after notice and opportunity for hearing, that the State has taken such steps as necessary to assure that the electric utility rate increases attributable to compliance with sulfur dioxide emission reduction requirements under section 181 are--

``(1) substantially equivalent for residential electric utility ratepayers throughout the State, and

``(2) substantially levelized over the period during which such requirements are in effect.

``(e) EPA RULES REGARDING DETERMINATION OF AMOUNT OF SUBSIDY.--The Administrator shall promulgate rules regarding the determination and approval by the Administrator of the amount of electric utility rates which are qualified for subsidy payments under this section. The rules shall provide for approval of such amounts only if the Administrator determines, based upon information submitted by the utility and upon any other information available to the Administrator, that the utility's costs of compliance with such requirements, the methods financing such costs, the accounting systems used by the utility with respect to such costs, and any other circumstances relating to compliance with the requirements of this part are such that the Administrator is satisfied that the costs of compliance are not unreasonable or excessive. In the case of costs for the purchase, installation, and operation of any technological system of continuous emission reduction for the control of emissions of sulfur dioxide, such costs shall not be treated as attributable to the imposition of requirements under this part unless the system meets each of the following requirements:

``(1) The system is installed on a steam generating unit in order to comply with emission limitations established for that unit under State plan provisions adopted pursuant to section 181.

``(2) The steam generating unit is specifically designated by the Governor of the State as a unit on which a technological system of continuous emission control is to be installed for purposes of meeting such emission limitations.

``(3) The construction of the steam generating unit commenced on or before September 18, 1978 so that the unit is not subject to new source performance standards under 40 CFR 60.40a.

``(d) INELIGIBLE APPLICANTS.--No person who brings an action against the Administrator challenging the validity or application of any provision of this part shall be eligible to receive any interest subsidy payment under this section after the date on which such action is brought.

``SEC. 188. DEFINITIONS.

``As used in this part:

``(1) The terms `Steam generating unit', `electric utility', and `fossil fuel' have the same meanings as provided in regulations set forth in 40 CFR 60.41a.

``(2) The term `stationary source of industrial process emissions' means any major stationary source in any category of stationary sources (other than fossil fuel fired steam generating units) which the Administrator determines, by rule, contributes significantly to concentrations of sulfur dioxide in the ambient air.

``(3) The average monthly statewide emissions rate for any State for any air pollutant shall be calculated in accordance with the following formula: the sum of the quantity of fuel burned by each plant multiplied by the monthly emissions rate for that plant, divided by the fuel burned by all plants within the entire State.

``SEC. 189. INNOVATIVE TECHNOLOGIES.

``(a) INNOVATIVE TECHNOLOGY ALTERNATIVE.--The

Administrator may provide financial assistance to the owners or operators of stationary sources for the purpose of promoting the use of innovative emissions technologies to control sulfur dioxide, nitrogen oxides, and other emissions from fossil fuels covered under this Act. To qualify for assistance under this section, such technologies shall not be currently in general use, but, in the judgment of the Administrator in consultation with the Secretary of Energy, shall have the potential for commercial application within 10 years after the enactment of this part. Such assistance shall be funded from revenues as set out in subsection (f).

``(b) DESIGN AND FEASIBILITY STUDIES.--The assistance made available under this section may include funds for the development of initial designs and feasibility studies to evaluate costs and benefits associated with proposals using an innovative technology. To be eligible for funding under this section, the Administrator must judge the technology to be cost-effective, environmentally beneficial, or effective in preventing switching of fuel sources. In evaluating proposals for funding under this section, the Administrator shall consider each of the following:

``(1) The social costs, including employment dislocation associated with fuel switching.

``(2) The economic impacts including comparative costs of capital, operating, and maintenance expenses,

and energy-efficiency.

``(3) The environmental benefits including comparative effects on air, water and solid waste.

``(c) CAPITAL COSTS AND OPERATION AND MAINTENANCE.--Under this section, the Administrator may award grants to share in the cost of the total annualized costs of controls, including capital, and operating and maintenance costs associated with innovative technologies. To qualify for assistance, the Administrator must determine that the project's economic, environmental or social benefits, as described in subsection (b) would be greater than those of the conventional technology.

``(d) STATE PLANS.--A State plan under this part may provide for compliance with the requirements of this part through the use of innovative technology at any stationary source in the State. If innovative technology is to be used for such purposes, the State plan shall also include other contingent emission limitations and compliance schedules applicable to any stationary source in the State. The contingent emission limitations shall take effect if the innovative technology installed on a unit fails to meet the emission limitations and compliance schedules applicable to that unit under the State plan. The contingent emission limitations shall be adequate to achieve emission reductions at least equivalent to the emission reductions which the innovative technology failed to achieve. Such contingent emission limitation requirements shall be adequate to assure that the State will meet the average monthly emission rates and deadlines set forth in section 181.

``(e) SUBSEQUENT PLAN REVISIONS.--In order to permit the use of innovative technology after the date of approval of a State plan under this part, the State may submit to the Administrator amendments to plan provisions adopted under this part at any time after such approval. The plan amendments shall be approved by the Administrator if he determines that the plan, as amended, will be adequate to achieve compliance with the the average monthly emission rates and deadlines set forth in this part.

``(f) FEES.--Upon the application of any State, the Administrator may promulgate regulations imposing a fee not to exceed 0.25 mills per kilowatt hour on the generation of electric energy in that State. The revenues derived from such fee shall be made available by the Administrator, subject to appropriation, solely for the purpose of promoting the use of innovative technologies as defined in section 188(a) in that State. The failure or refusal of any person subject to such fee to pay the fee or to file any report or other document required by the Administrator in connection with the imposition of such fee shall be subject to the same penalties and sanctions as are applicable to the fee imposed under

section 185.

``(g) REPORT.--In its annual report to the Congress before January 1, 1994, the Administrator shall report on the status of innovative technologies which are available, or which may be available, to meet the requirements of this part.

SEC. 102. REVISIONS OF NEW SOURCE PERFORMANCE STANDARDS FOR CONTROL OF NITROGEN OXIDE EMISSIONS.

Section 111 of the Clean Air Act is amended by adding the following new subsections at the end thereof:

``(k) NOX EMISSIONS FROM CERTAIN ELECTRIC UTILITY BOILERS.--The Administrator shall revise the standards of performance for emissions of nitrogen oxides from electric utility steam generating units which burn bituminous or subbituminous coal. Such revised standards shall prohibit the emission of nitrogen oxides from such units at a rate which exceeds:

``(1) 0.35 pounds per million Btu's, in the case of subbituminous coal, based on a 30-day rolling average.

``(2) 0.40 pounds per million Btu's, in the case of bituminous coal, based on a 30-day rolling average.

Such revised standard shall take effect with respect to units which commence construction after the date of the enactment of this subsection. As used in this subsection, the terms `electric utility steam generating unit', `bituminous coal and 'subbituminous coal' have the same meanings as when used in 40 C.F.R. part 60, subpart Da, as in effect on January 1, 1983.

``(1) NSPS FOR NO_x EMISSIONS FROM INDUSTRIAL BOILERS.--The Administrator shall promulgate standards of performance under this section for emissions of oxides of nitrogen from all fossil-fuel-fired steam generating units which meet each of the following requirements:

``(1) The units are new sources within the meaning of subsection (a)(2).

``(2) The units are capable of combusting more than 50 million Btu's per hour heat input of fossil fuel (either alone or in combination with any other fuel).

``(3) The units are not owned or operated by an electric utility.

The standards under this section applicable to fossil-fuel-fired steam generating units which are capable of combusting more than 250 million Btu's per hour heat input may vary from the standards applicable to units which are not capable of combusting more than 250 million Btu's per hour heat input.''.

SEC. 103. SMELTERS.

Section 119(c)(2) of the Clean Air Act is amended by adding the following at the end thereof: ``Each primary nonferrous smelter which has applied for, or been granted, a

second order under this section with respect to an emission limitation or standard for sulfur oxides under the applicable implementation plan shall be in compliance with such limitation or standard by January 2, 1988. No order under section 113 and no action under any authority contained in this Act or in any other provision of law (including any State implementation plan) and no order of any court shall permit any extension or delay of the effective date of such compliance beyond January 2, 1988. Within 180 days after the date of the enactment of this sentence, the Administrator shall complete action on all applications for an order under this section which are pending on such date. Within 60 days after the date of the enactment of this sentence, the Administrator shall amend each order in effect on such date under this section to require final compliance by the primary nonferrous smelter before January 2, 1988, with the emission limitations and standards for sulfur oxides under the applicable implementation plan.''.

SEC. 104. CONFORMING AMENDMENTS.

The Clean Act Act is amended as follows:

(1) Section 113(a)(3) is amended by inserting ``or is in violation of any requirement in effect pursuant to subpart 1 of part E,'' after ``inspections, etc.)''.

(2) Section 113(b) is amended by inserting the following immediately after paragraph (5): ``Whenever any

person violates any requirement in effect pursuant to subpart 1 of part E, the Administrator may commence a civil action for permanent or temporary injunction or to assess and recover a civil penalty of not more than $25,000 per day of violation, or both.''.

(3) Section 113(c)(1)(C) is amended by inserting ``or violates any requirement in effect pursuant to subpart 1 of part E,'' before ``or''.

(4) Section 307(b)(1) is amended by inserting ``, any final action taken by the Administrator under part E of title I'' after ``120'' in the first sentence thereof.

TITLE II—CONTROL OF EMISSIONS FROM MOBILE SOURCES

SEC. 201. EMISSIONS OF OXIDES OF NITROGEN.

(a) NOx EMISSIONS FROM CERTAIN MOTOR VEHICLES.--Section 202 of the Clean Air Act is amended by adding the following new subsection at the end thereof:

``(g) NOx EMISSIONS FROM CERTAIN MOTOR VEHICLES.--Effective with respect to the model years specified in table 1, the regulations under subsection (a) applicable to emissions of oxides of nitrogen from the motor vehicles (and from motor vehicle engines for such vehicles) specified in table 1 shall contain standards which provide that such emissions may not exceed the level specified in table 1:

TABLE 1

NOX EMISSIONS FROM CERTAIN PASSENGER CARS AND TRUCKS

Vehicle Type	Model Year	Standard
Passenger cars	1989 and after	0.7 gpm
Gasoline and diesel powered trucks weighing up to 6,000 lbs	1988 and after	1.2 gpm
Gasoline and diesel powered trucks weighing from 6,000 up to 8,500 lbs	1988 and after	1.7 gpm

The weights specified in the first column of table 1 (and in table 2 of subsection (h)) shall be based upon the gross vehicle weight rating determined by the Administrator. In the case of any motor vehicle specified in the table (and in the case of motor vehicle engines for such vehicles) the standard established pursuant to this subsection shall apply in lieu of any standard otherwise applicable pursuant to this section.

``(h) HYDROCARBON STANDARDS FOR TRUCKS.--Effective with respect to model year 1990 and thereafter, the regulations under subsection (a) applicable to emissions of hydrocarbon from the motor vehicles (and from motor vehicle engines for such vehicles) specified in the first column of table 2 shall contain standards which provide that such emissions may not exceed the level specified in the second column of table 2:

TABLE 2

HYDROCARBON STANDARD FOR TRUCKS: MODEL YEAR 1990 AND AFTER

Vehicle Type	Standard
Trucks weighing up to 6,000 lbs	0.41 gpm
Trucks weighing from 6,000 up to 8,500 lbs	0.53 gpm

In the case of any motor vehicle specified in the table (and in the case of motor vehicle engines for such vehicles) the standard established pursuant to this subsection shall apply in lieu of any standard otherwise applicable pursuant to this section''.

(b) DEFINITIONS.--Section 216 of the Clean Air Act is amended by adding the following at the end thereof:

``(6) The terms `passenger car' and `truck' shall have such meaning as shall be prescribed by the Administrator.

``(7) The term `gpm' means grams per mile.

``(8) The term `g/Bhp' means grams per brake horsepower hour.

(c) REGULATION OF SULFUR IN DIESEL FUEL.--

(1) 0.05 PERCENT LIMIT.--Section 211 of the Clean Air Act is amended by adding the following new subsection at the end thereof:

``(h) REGULATION OF SULFUR IN DIESEL FUEL.--The Administrator shall promulgate regulations under this

subsection requiring that the sulfur content of any motor vehicle diesel fuel shall not exceed 0.05 percent (by weight). After January 1, 1989, no manufacturer or processor of motor vehicle diesel fuel may sell, offer for sale, or introduce into commerce any fuel which does not comply with such regulations. In the case of a State standard which is more stringent than the standard under this subsection, section 211(c)(4)(A) shall not apply to regulations regarding the sulfur content of any motor vehicle diesel fuel.

(2) ENFORCEMENT.--Section 211(d) of such Act is amended by inserting after ``under subsection (c)'' the following ``or (h)''.

(d) EVAPORATIVE HC.--Section 202(a)(6) of the Clean Air Act is amended to read as follows:

``(6) EVAPORATIVE HC.--Not later than 6 months after the enactment of this paragraph, the Administrator shall promulgate regulations requiring one or both of the following on a nationwide basis:

``(A) The use of onboard hydrocarbon control technology by motor vehicles manufactured for any model year after the model year 1989.

``(B) The use of gasoline vapor recovery of hydrocarbon emissions emanating from the fueling of motor vehicles.''.

(g) CONFORMING AMENDMENT.--Section 202(a)(3)(A)(ii) of the Clean Air Act is amended by inserting ``and except as otherwise provided in subsections (g), (h), and (i)'' after ``(E)''.

TITLE III--INTERNATIONAL COOPERATION.

SEC. 301. INTERNATIONAL COOPERATION.

(a) ANNEX TO BORDER AGREEMENT.--The Congress expresses its concern and sense of urgency regarding the ongoing and prospective environmental impacts of transboundary air pollution between the United States and Mexico, particularly from existing and future point sources of sulfur dioxide in both countries. The Congress finds that the progress of the United States in negotiating an Annex concerning transboundary air pollution to the August 4, 1983, United States-New Mexico Border Environmental Agreement has been unsatisfactory and therefore directs the Secretary of State and the Administrator of the Environmental Protection Agency to, with all due dispatch, conclude with the Government of Mexico an Annex concerning transboundary air pollution to the 1983 Border Environmental Agreement. All feasible efforts shall be made to conclude a final version of said Annex as soon as possible and in no case later than 3 months after enactment of this section.

(b) NEGOTIATIONS.--

(1) In negotiating the Annex referred to in subsection (a), the Secretary shall give special emphasis

to ensuring that an agreement is concluded that will ensure that the Nacozari smelter in Mexico will meet pollution control standards that are at least as stringent as new source performance standards under the Clean Air Act, as codified in 40 CFR part 60 subpart p, preferably before start-up of that smelter but in no case later than January 1, 1988.

(2) In negotiating such Annex the Secretary shall ensure that an agreement is concluded that will ensure that the Cananea smelter in Mexico will--

(A) at a minimum, achieve a level of pollution control for any increased emissions before any proposed expansion that is at least as stringent as new source performance standards under the Clean Air Act, as codified at 40 CFR part 60 subpart p; and

(B) if technically feasible, achieve that level of pollution control for the entire source before any expansion.

(3) In negotiating such Annex the Secretary shall ensure that an agreement is concluded for a mutually acceptable arrangement for monitoring, inspection and enforcement of pollution control standards for copper smelters in both countries in the air quality control region (within 100 kilometers in each direction from the border) encompassing the copper smelters at Douglas,

Arizona; Nacozari, Sonora; and Cananea, Sonora.

(4) In negotiating such Annex the Secretary shall promote a final version that in its other provisions is in no case less stringent in terms of absolute emissions and ambient air quality standards, and in the schedule for coming into force of such standards, then set out in the July 18, 1985, joint communique of the national coordinators of the 1983 Border Agreement.

(c) REPORT.--The Secretary of State and the Administrator of the Environmental Protection Agency shall submit a report to Congress no later than 6 months after enactment of this section, on their implementation of subsections (a) and (b) of this section.

(d) FIELD EXPERIMENTS.--The Environmental Protection Agency shall perform atmospheric field experiments to determine the effects of emissions of sulfur dioxide from the Nacozari smelter in Mexico, before and after implementation of pollution controls, on concentrations of oxides of sulfur and deposition thereof in the States of Arizona, Colorado, Idaho, Montana, New Mexico, Utah, and Wyoming. The experiments shall place particular emphasis on the effects of the smelter, before and after implementation of pollution controls, on acid rain and visibility in the above-mentioned States.

(e) STUDY AND REPORT.--The Secretary of State, in

consultation with the Administrator of the Environmental Protection Agency, shall establish a duly constituted international agency, or make use of an already constituted international agency to prepare and report on the effects of transboundary air pollution originating from copper smelters on public health and welfare in the United States and in Mexico. The study and report shall address, to the extent available data permit, the magnitude and effects of transborder pollution by sulfur dioxide, including pollution expected from further industrial expansion. The report shall make a finding as to whether such transborder pollution by sulfur dioxide originating from copper smelters may reasonably be expected to endanger public health and welfare in the territories of the United States and in Mexico and shall make recommendations for prevention or elimination of such endangerments as may be documented in the report.

APPENDIX B

ARGONNE REGIONAL ENERGY PRICE SIMULATOR (AREPS): ELECTRICITY PRICE PROJECTIONS

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ARGONNE REGIONAL ENERGY PRICE SIMULATOR (AREPS): ELECTRICITY PRICE PROJECTIONS

AREPS was developed as part of the National Acid Precipitation Assessment Program (NAPAP) under Task Group I (Emissions and Controls). This task group is developing an emission projection model set for major sectors and suspected air pollutants. The various emission projection models need to be provided with consistent economic and energy input data. The purpose of AREPS is to provide consistent long-run energy price projections by sector and state or multistate regions. A more-detailed description of AREPS is found elsewhere.[30] A brief description of the framework used to produce electricity price projections is provided below.

The electricity projection module in AREPS incorporates several features:

- It provides electricity prices by the three major sectors: residential, commercial, and industrial.
- It is consistent with the national projections of electricity rates contained in the DOE National Energy Policy Plan, which forecasts rates by the three major sectors to the year 2010 (DOE and Argonne have also provided a long-term extension to the year 2030).
- It utilizes the regional projections of electricity rates prepared by Data Resources, Inc., (DRI) for 11 regions. These DRI projections are based on revenue requirement analyses and electricity demand projections.
- It makes use of historic price differences between states in a region.

The data and variables associated with the above features are represented with the following notation:

$PE_{i,s}(t)$ = state's electricity price projection in sector i in year t

$PENEPP_i(t)$ = national electricity price projection from NEPP in sector i in year t

$PEDRIUS_i(t)$ = national electricity price projection from DRI in sector i in year t

$PEDRI_{i,r}(t)$ = region r electricity price projection from DRI in sector i in year t

$PEBASE_{i,s}$ = state's electricity price in sector i in base year (1980).

$PEBASEAV_{i,r}$ = weighted average of base-year state electricity prices among states contained in region r for sector i.

There are two steps to the electricity price projection procedure employed in AREPS: (1) scaling the DRI regional electricity price projections to be consistent with NEPP and (2) incorporating state-level variations. Step 1 is accomplished by introducing a scale factor for each projection year t.

$$SCALE_i(t) = PENEPP_i(t)/PEDRIUS_i(t) \tag{A.1}$$

The adjusted DRI regional projections are obtained by applying this scale factor

$$PEADJDRI_{i,r}(t) = SCALE_i(t) * PEDRI_{i,r}(t) \tag{A.2}$$

The state-level projection (step 2) is then computed as

$$PE_{i,s}(t) = PEADJDRI_{i,r}(t) + ALPHA(t)*[PEBASE_{i,s} - PEBASEAV_{i,r}] \tag{A.3}$$

In words, equation A.3 states that the state projection is equal to its regional projection (adjusted for national level consistency with NEPP) plus a state-specific deviation term. This deviation term in future years is equal to the base-year deviation term scaled by a factor ALPHA(t); ALPHA(t) is a value less than one. The ALPHA factor is intended to represent "regression toward the mean," a phenomenon often observed in statistical data. That is, our best estimate for the state price will tend toward the regional mean over time rather than further diverge from the regional mean. Whereas the probability distribution of state price projections is likely to widen over time, our best estimate of the mean of this distribution is likely to move closer to the regional mean.

APPENDIX C

DESCRIPTION OF THE FINANCIAL MODULE FOR COMPUTING ELECTRICITY RATES

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DESCRIPTION OF THE FINANCIAL MODULE FOR COMPUTING ELECTRICITY RATES

When a utility makes expenditures for pollution control, it will want to recover these expenditures through increased revenue requirements. Electricity rates will increase depending on the increased revenue requirements, the level of electricity demand, and the allocation of increased revenue requirements among the major customer categories: residential, commercial, and industrial.

The electricity demand projections by state and sector (i.e., residential, commercial, and industrial) are prepared by the Argonne Regionalization Activity Module (ARAM). The methodology used in ARAM is described elsewhere.[9,10] However, it should be pointed out that ARAM controls to NEPP-V at the national level for each sector. Differential growth rates in electricity demand by state are based on DRI state forecasts of population growth, commercial employment, and industrial employment for the respective sectors.

The revenue requirements (RR) are calculated for pollution control outlays. Four types of items give rise to RR: variable costs, return on the rate base, depreciation, and taxes. Variable costs are (1) the fuel premium associated with switching to more-expensive lower-sulfur coal and (2) the increased O&M costs associated with fuel switching or adding a scrubber. Variable costs can be a substantial share of total RR. It is often assumed that variable costs are constant in real terms. That is, these costs increase in nominal dollars at the inflation rate.

The return on the rate base is the return-on-capital. The rate base consists of the historical cost of capital assets minus depreciation. For states that use normalized accounting (as opposed to flow-through accounting), the rate base is adjusted to exclude certain tax benefits that are allowed by the state Public Utility Commission. The rate of return on the adjusted rate base depends on the fraction of debt, common stock, and preferred stock financing and the allowed returns on each of these fractions. The cost of new debt is taken to be 10%. The cost of capital for common and preferred stock is state-specific as in the AUSM finance module.

In terms of cost-of-service accounting, depreciation is the return-of-capital (i.e., the utility is receiving back its original capital outlay). Return-of-capital is based on straight-line depreciation of the original rate base, including allowance for funds used during construction (AFUDC).

Also as part of RR, the utility is allowed to recover from its customers the taxes that it pays (plus some additional tax benefits). Taxes include federal and state income taxes, property taxes, and gross sales taxes. Under normalized accounting, the federal income tax benefits of accelerated depreciation of FGD equipment and investment tax credits (ITC) on this equipment do not flow through to decrease customer rates in the year in which they occur. Instead the utility can collect RR as if it used straight-line depreciation for tax purposes and as if ITC were spread over the life of the equipment.

Associated with a specific emission control program, RR are calculated as described above. Based on these RR and sectoral demand, two alternative impacts on electricity rates are calculated: (1) equal percentage increases in all three sectors or (2) residential rates absorbing the total impact. (Of course there are many other alternatives between these two that the utility commission could choose.) The reason that the second option might be selected is that the price elasticity in the industrial sector might be high and that under the emission control program, residential rate increases in excess of 10% would be subsidized by a national fund.

RR and electricity rate impacts are front-end-loaded (i.e., initially high and then decline). There are several reasons for this. RR decrease as the rate base is depreciated. Also, unlike variable costs, the remaining components of RR do not tend to increase with inflation. Hence, when discounted to real (or constant) dollars, future impacts are discounted. Finally, electricity rate impacts decrease as projected electricity demand grows, since RR can be spread over more electricity sales.

The specific equations used to calculate RR are the following:

$$RR_t = [VAR_t + RRB_t + RBDEP_t + TF_f + TS_t] * [1 + GRTXR * (1 - ETXR)] \tag{C.1}$$

where:

RR_t = revenue requirement in year t;

VAR_t = variable costs of producing and providing electricity to the customers;

RRB_t = return on utility rate base which indicates debt and equity capital costs;

$RBDEP_t$ = rate base depreciation for year t;

TF_t = federal taxes in year t;

TS_t = state taxes in year t;

GRTXR = applicable gross receipts tax rate;

ETXR = effective state and federal combined corporate income tax rate, reflecting that the gross receipts tax is an income tax deduction.

In the price module, the additional variable costs and rate base items associated with a given pollution control program (as provided by AIRCOST) are added to Eq. C.1 using the following calculation for additional revenue requirements.

$$ADDRR_t = [ADDVAR_t + ADDRRB_t + ADDRBDEP_t + ADDTF_t + ADDTS_t] * [1 + GRTXR * (1 - ETXR)] \tag{C.2}$$

where:

$ADDRR_t$ = additional revenue requirement in year t due to emissions control.

$ADDVAR_t$ = additional variable costs in year t, including fuel costs, operation and maintenance costs, etc.

$ADDRRB_t$ = additional return on rate base. This is calculated by applying the historical returns (rates) on the pollution control rate base additions.

ADDRBDEP = additional depreciation expense in year t due to the pollution control activity.

$ADDTF_t$ = added federal tax in year t.

$ADDTS_t$ = added state tax in year t.

The rate base additions are assumed to be financed through equity.

APPENDIX D

STATISTICS ON ELECTRICITY-INTENSIVE INDUSTRIES IN HIGH-IMPACT STATES

TABLE D.1 Statistics on Electricity-Intensive Industries

Industry	SIC Code	Value of Shipments (1980$ x 10^6)	Electricity Purchased (kWh x 10^6)	Electricity Cost as percent of: Value Added	Electricity Cost as percent of: Value of Shipments	Electricity Rate ¢/kWh (1982$)	Ratio to Industrial Average Rate (3.84¢/kWh)
Cotton seed oil mills	2074	1,033.7	540.7	10.7	2.0	4.61	1.20
Manufactured ice	2097	169.6	460.7	15.6	11.0	4.70	1.23
Particle board	2492	512.4	825.1	11.4	4.8	3.44	0.90
Alkalies and chlorine	2812	1354.1	10,679.5	45.5	19.6	2.89	0.75
Industrial gases	2813	1,539.6	11,958.6	42.4	24.5	3.66	0.95
Other industrial inorganic chemicals	2819	12,095.9	37,092.0	13.9	7.5	2.86	0.75
Carbon black	2895	498.0	540.4	13.3	3.5	3.78	0.99
Reclaimed rubber	3031	38.3	75.4	12.2	7.8	4.62	1.20
Cement, hydraulic	3241	3962.4	9,237.9	15.3	8.2	4.08	1.06
Lime	3274	598.8	813.8	10.8	5.1	4.38	1.14
Mineral wool	3296	2,235.4	2,703.5	7.3	4.0	3.82	0.99
Electrometallurgical products	3313	1,249.3	6,814.3	42.0	13.8	2.94	0.77
Malleable iron foundries	3322	521.2	1,015.5	11.9	7.0	4.17	1.09
Primary zinc	3333	413.1	1,487.8	51.7	8.3	2.67	0.70
Primary aluminum	3334	6,979.9	72,279.1	39.3	15.6	1.75	0.47
Other primary nonferrous metals	3339	1,906.6	4,279.4	15.6	5.1	2.66	0.69
Carbon and graphite products	3624	1,183.3	2,171.8	7.5	4.2	2.64	0.69

Source: Office of Technology Assessment, "Acid Rain and Transported Air Pollutants: Implications for Public Policy," OTA-0-204 (June 1984).

TABLE D.2 Number of Establishments by State and Industry Group

Industry	SIC Code	Ill.	Ind.	Mo.	N.H.	Ohio	Penn.	W.V.	U.S.
Cotton seed mills	2074	0	0	0	0	0	0	0	77
Manufactured ice	2097	0	0	0	0	0	0	0	589
Particle board	2492	0	0	0	0	0	0	0	54
Alkalies & chlorine	2812	0	0	0	0	3	0	2	51
Industrial gases	2813	23	14	9	0	37	36	0	563
Other industrial inorganic chemicals	2819	30	16	11	0	46	41	0	645
Carbon black	2895	0	0	0	0	0	0	0	25
Reclaimed rubber	3031	3	0	0	0	7	0	0	26
Cement, hydraulic	3241	5	5	11	0	9	24	4	237
Lime	3274	4	0	3	0	8	9	0	87
Mineral wool	3296	6	11	3	0	16	17	1	179
Electrometallurgical products	3313	0	0	0	0	8	1	4	41
Malleable iron foundries	3322	0	0	0	2	5	5	0	50
Primary zinc	3333	2	0	0	0	0	1	0	8
Primary aluminum	3334	0	1	1	0	1	0	0	34
Other primary nonferrous metals	3339	0	0	0	0	4	8	0	90
Carbon and graphite	3624	5	0	0	0	13	9	2	91
Total		78	47	38	2	157	151	13	2847

Source: Bureau of the Census, "1982 Census of Manufactures, Industry Series" Department of Commerce (MC82-I).

TABLE D.3 Employment by State and Industry Group (10^3)[a]

Industry	SIC Code	Ill.	Ind.	Mo.	N.H.	Ohio	Penn.	W.V.	U.S.
Cotton seed mills	2074	0	0	0	0	0	0	0	5.2
Manufactured ice	2097	0	0	0	0	0	0	0	5.0
Particle board	2492	0	0	0	0	0	0	0	5.6
Alkalies & chlorine	2812	0	0	0	0	0.2	0	1.0-2.499	7.6
Industrial gases	2813	0.150-0.249	0.4	0.150-0.249	0	0.4	0.5	0	7.3
Other industrial inorganic chemicals	2819	2.8	0.500-0.999	0.4	0	6.3	2.8	0	81.7
Carbon black	2895	0	0	0	0	0	0	0	7.1
Reclaimed rubber	3031	0.250-0.499	0	0	0.250-0.499	0	0	0	0.8
Cement, hydraulic	3241	0.6	0.7	0.9	0	0.500-0.999	2.2	0.150-0.249	24.6
Lime	3274	0.150-0.249	0	1.0-2.499	0	0.5	1.0	0	5.6
Mineral wool	3296	0.4	1.4	0.150-0.249	0	3.5	1.5	0.250-0.499	19.7
Electrometallurgical products	3313	0	0	0	0	2.3	0.150-0.249	0.500-0.999	5.3
Malleable iron foundries	3322	0	0	0	0.150-0.249	0.6	0.500-0.999	0	6.5
Primary zinc	3333	0.250-0.499	0	0	0	0	0.500-0.999	0	2.0
Primary aluminum	3334	0	1.0-2.499	1.0-2.499	0	1.0-2.499	0	0	22.9
Other primary nonferrous metals	3339	0	0	0	0	1.0-2.499	0.250-0.499	0	9.2
Carbon and graphite	3624	0.3	0	0	0	1.2	3.2	0.500-0.999	12.1
Total		4.9-5.596	4.0-5.598	3.6-6.397	0.150-0.249	17.75 21.496	12.6-13.946	2.4-5.245	223.2

[a]Employment ranges are reported where disclosure problems existed.

Source: Bureau of the Census, "1982 Census of Manufactures, Industry Series" Department of Commerce, (MC82-I).

TABLE D.4 Value of Shipments by State and Industry Group (1980 \$ x 10^6)[b]

Industry	SIC Code	Ill.	Ind.	Mo.	N.H.	Ohio	Penn.	W.V.	U.S.
Cotton seed mills	2074	0	0	0	0	0	0	0	933.3
Manufactured ice	2097	0	0	0	0	0	0	0	228.2
Particle board	2492	0	0	0	0	0	0	0	574.4
Alkalies & chlorine	2812	0	0	0	0	46.2 (2.94)	0	--[a]	1570.5
Industrial gases	2813	--[a]	156.9 (7.77)	--[a]	0	119.7 (5.93)	108.9 (5.39)	0	2019.3
Other industrial inorganic chemicals	2819	510.2 (4.23)	--[a]	90.0 (0.75)	0	832.1 (6.90)	448.9 (3.72)	0	12060.4
Carbon black	2895	0	0	0	0	0	0	0	632.9
Reclaimed rubber	3031	--[a]	0	0	0	--[a]	0	0	63.0
Cement, hydraulic	3241	70.7 (2.00)	85.7 (2.42)	123.2 (3.48)	0	--[a]	264.3 (7.46)	--[a]	3542.0
Lime	3274	--[a]	0	--[a]	0	45.6 (8.39)	97.4 (17.9)	0	543.2
Mineral wool	3296	35.7 (1.57)	139.0 (6.09)	--[a]	0	369.6 (16.20)	139.1 (6.10)	--[a]	2281.1
Electrometallurgical products	3313	0	0	0	0	250.5 (35.41)	--[a]	--[a]	707.5
Malleable iron foundries	3322	0	0	0	--[a]	31.4 (9.72)	--[a]	0	323.2
Primary zinc	3333	--[a]	0	0	0	0	--[a]	0	334.0
Primary aluminum	3334	0	--[a]	--[a]	0	--[a]	0	0	5037.1
Other primary nonferrous metals	3339	0	0	0	0	--[a]	--[a]	0	2312.9
Carbon and graphite	3624	16.0 (1.63)	0	0	0	86.0 (8.77)	163.6 (16.68)	--[a]	980.4

[a]Not reported in the data source due to disclosure problems.

[b]Values in parentheses () represent state share (%) of total (U.S.) industry activity.

Source: Bureau of the Census, "1982 Census of Manufactures Industry Series" Department of Commerce (MC82-I).

TABLE D.5 Value Added by State and Industry Group (1980 $ x 10^6)[c]

Industry	SIC Code	Ill.	Ind.	Mo.	N.H.	Ohio	Penn.	W.V.	U.S.
Cotton seed mills	2074	0	0	0	0	0	0	0	202.9
Manufactured ice	2097	--	--	--	--	--	--	--	--[b]
Particle board	2492	0	0	0	0	0	0	0	193.3
Alkalies & Chlorine	2812	0	0	0	0	27.5 (3.77)	0	--[a]	728.8
Industrial gases	2813	--[a]	75.3 (7.14)	--[a]	0	59.0 (5.59)	62.1 (5.88)	0	1055.3
Other industrial inorganic chemicals	2819	259.9 (4.11)	--[a]	28.5 (0.45)	0	450.7 (7.13)	165.7 (2.62)	0	6321.4
Carbon black	2895	0	0	0	0	0	0	0	190.8
Reclaimed rubber	3031	--[a]	0	0	0	--[a]	0	0	31.2
Cement, hydraulic	3241	31.5 (1.73)	41.1 (2.26)	61.0 (3.36)	0	--[a]	111.3 (6.13)	--[a]	1815.7
Lime	3274	--[a]	0	--[a]	0	17.1 (6.98)	43.9 (17.91)	0	245.0
Mineral wool	3296	14.6 (1.18)	78.3 (6.33)	--[a]	0	209.2 (16.92)	81.6 (6.60)	--[a]	1236.7
Electrometallurgical products	3313	0	0	0	0	79.4 (44.04)	--[a]	--[a]	180.3
Malleable iron foundries	3322	0	0	0	--[a]	21.3 (10.32)	--[a]	0	206.3
Primary zinc	3333	--[a]	0	0	0	0	--[a]	0	60.6
Primary aluminum	3334	0	--[a]	--[a]	0	--[a]	0	0	1133.9
Other primary nonferrous metals	3339	0	0	0	0	--[a]	--[a]	0	581.3
Carbon and graphite	3624	9.4 (1.69)	0	0	0	45.2 (8.15)	111.0 (20.0)	--[a]	554.9

[a]Not reported in the data source due to disclosure problems.

[b]Suppressed in preliminary report.

[c]Values in parentheses () represent state share (%) of total (U.S.) industry activity.

Source: Bureau of the Census, "1982 Census of Manufactures, Industry Series" Department of Commerce, (MC82-I).

TABLE D.6 Average State Electricity Rates for Electricity-Intensive Industry Groups

Industry	SIC Code	Electricity Rate (¢/kWh, 1980 $)							
		Ill.	Ind.	Mo.	N.H.	Ohio	Penn.	W.V.	U.S.
Fats & oils	207	3.29	3.37	3.77	--	3.88	--[a]	--	3.66
Misc. foods, kindred products	209	4.67	--	4.04	--	3.89	--[a]	--	4.26
Misc. wood products	249	--	3.76	4.46	5.10	4.35	--[a]	--	3.56
Industrial inorganic chemicals	281	3.18	--[a]	--[a]	--	2.14	2.96	--[a]	2.63
Misc. chemical products	289	4.61	--	2.73	--	3.64	4.07	--	3.72
Reclaimed rubber	303	--	--	--	--	--	--	--	3.98
Cement, hydraulic	324	--	--	--	--	2.91	3.60	--	3.52
Concrete, gypsum, plaster prod.	327	4.57	3.59	--[a]	--	4.55	4.50	--[a]	4.37
Misc. nonmetallic mineral prod.	329	4.33	3.67	--[a]	4.94	3.21	3.66	--[a]	3.60
Blast furnace, basic steel prod.	331	3.54	4.07	--	--	2.98	3.68	--[a]	3.38
Iron & steel foundries	332	3.84	3.68	3.99	4.82	4.06	4.17	--[a]	3.96
Primary nonferrous metals	333	--	--	--[a]	--	--	--[a]	--	1.60
Electrical industrial apparatus	362	--[a]	3.07	3.36	5.66	3.88	2.84	--	3.19
State industry average		3.99	3.17	3.20	5.04	3.11	3.93	2.46	

[a]Not reported in data source due to disclosure problems.

Source: Computed from data reported in: Bureau of the Census, "1980 Annual Survey of Manufactures, Fuels and Electric Energy Consumed, States by Industry Group and Standard Metropolitan Statistical Area by Nation Industry Group [M80(AS)-4.2]," U.S. Department of Commerce (Oct. 1982).